



# **NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL**

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

## **NERC-NAESB-ISO/RTO Council Joint Interface Committee**

**July 16, 2004 (11 a.m.–3 p.m. EDT)**

**FRCC Offices**

**Tampa, Florida**

### **AGENDA**

#### **Meeting Location**

FRCC Offices

1408 N. Westshore Blvd., Suite 1002

Tampa, FL 33607-4512

Phone (813) 289-5644

#### **Conference Line Information**

Dial In Number: 888-810-3142

Pass Code: JIC

Conference Leader: Rae McQuade

### **Agenda**

#### **1. Administrative Items**

- a. Introductions
- b. Roster and Quorum
- c. Antitrust Guidelines
- d. February 18–19, 2004 Meeting Minutes (**Approve**)
- e. June 24, 2004 Conference Call Minutes (**Approve**)
- f. Meeting Agenda and Objectives

#### **2. Version 0 Standards Proposals**

- a. NERC Version 0 Standards
- b. NAESB Version 0 Standards
- c. JIC Consideration of Proposed NERC and NAESB Version 0 Standards

#### **3. Other Business**

- a. Other Business
- b. Future Meetings and Conference Calls

### **Adjourn**

**Background for Agenda Item 1 – Administrative Items**

Item 1a — Co-Chairs Linda Campbell, Michael Deselle, and Karl Tammar will lead the introduction of JIC members and guests.

Item 1b — Secretary Cauley will check attendance and determine the presence of a quorum. The current JIC roster is provided in **Attachment 1**.

Item 1c — Rae McQuade will review the Antitrust Guidelines.

Item 1d — Secretary Cauley will present the draft minutes of the February 18–19, 2004 JIC meeting for approval (**Attachment 2**).

Item 1e — Secretary Cauley will present the draft minutes of the June 24, 2004 JIC conference call for approval (**Attachment 3**).

Item 1f — Co-chair Michael Deselle will review the meeting agenda and objectives.

**Background for Agenda Item 2 — Version 0 Standards Proposals**

Item 2a — Gerry Cauley will provide an overview of the NERC proposal to develop Version 0 Reliability Standards, including status of the development effort. Background materials provided are:

**Attachment 4** — SAR for Version 0 Reliability Standards

**Attachment 5** — NERC Standards Transition Plan

**Attachment 6** — Version 0 Reliability Standards Background Information

**Attachment 7** — Version 0 Reliability Standards Comments Form

**Attachment 8** — Preliminary Draft Operating Standards

**Attachment 9** — Preliminary Draft Planning Standards

Item 2b — Rae McQuade will provide an overview of the NAESB proposal to develop Version 0 Business Practice Standards, including status of the development effort. Background materials provided are:

**Attachment 10** — NAESB Request and Plan for Version 0 Business Practice Standards

**Attachment 11** — NAESB Version 0 Comments Letter

**Attachment 12** — NAESB Version 0 Time Error Correction Standard

**Attachment 13** — NAESB Version 0 Time Error Correction Documentation

**Attachment 14** — NAESB Version 0 Inadvertent Interchange Standard

**Attachment 15** — NAESB Version 0 Inadvertent Interchange Documentation

**Attachment 16** — NAESB Version 0 ACE Special Cases Standard

**Attachment 17** — NAESB Version 0 ACE Special Cases Documentation

**Attachment 18** — NAESB Version 0 Coordinate Interchange Standard

**Attachment 19** — NAESB Version 0 Coordinate Interchange Documentation

**Attachment 20** — NAESB Version 0 Emergency Operations Standard

**Attachment 21** — NAESB Version 0 Emergency Operations Documentation

**Attachment 22** — NAESB Version 0 Transmission Loading Relief Standard

**Attachment 23** — NAESB Version 0 Transmission Loading Relief Documentation

Item 2c — The JIC is requested to consider the NERC and NAESB proposed Version 0 standards and assign development to NERC or NAESB or remand the requests back to NERC and NAESB for further work and resolution of issues.

**Background for Agenda Item 3 — Other Business**

Item 4a — JIC members are requested to present any additional business for consideration of the JIC.

Item 4b — The JIC is requested to set meeting dates for the remainder of 2004.

## 2004 NAESB-NERC Joint Interface Committee

### NERC REPRESENTATIVES

**Linda Campbell (Co-Chair)**

Director of Reliability  
Florida Reliability Coordinating Council  
1408 North Westshore Boulevard  
Suite 1002  
Tampa, FL 33607-4512  
Phone: 813-289-5644  
Fax: 813-289-5646  
Email: [lcampbell@frcc.com](mailto:lcampbell@frcc.com)

**R. Scott Henry**

Director, Regulatory Policy  
Duke Power Company  
P.O. Box 1006  
Charlotte, NC 28201-1006  
Phone: 704-382-6182  
Fax: 704-382-4671  
Email: [rshenry@duke-energy.com](mailto:rshenry@duke-energy.com)

**Sam R. Jones**

Chief Operating Officer  
Electric Reliability Council of Texas  
2705 West Lake Drive  
Taylor, TX 76574-2136  
Phone: 512-248-3177  
Fax: 512-248-3992  
Email: [sjones@ercot.com](mailto:sjones@ercot.com)

**Edward A. Schwerdt**

Executive Director  
Northeast Power Coordinating Council  
1515 Broadway, 43<sup>rd</sup> Floor  
New York, NY 10036-8901  
Phone: 212-840-1070  
Fax: 212-302-2782  
Email: [eschwerdt@npcc.org](mailto:eschwerdt@npcc.org)

**Ed Tymofichuk**

Division Manager, Transmission System  
Operations  
Manitoba Hydro  
P.O. Box 815  
453 Dovercourt  
Winnipeg, Manitoba R3Y 1G4 Canada  
Phone: 204-487-5489  
Fax: 204-487-5360  
Email: [tetymofichuk@hydro.mb.ca](mailto:tetymofichuk@hydro.mb.ca)

**Mark Fidrych**

Power Operations Specialist  
Western Area Power Administration  
P.O. Box 3700  
MC J0003  
Loveland, CO 80539-3003  
Phone: 970-461-7240  
Fax: 970-461-7299  
Email: [fidrych@wapa.gov](mailto:fidrych@wapa.gov)

### NORTH AMERICAN ENERGY STANDARDS BOARD (NAESB) REPRESENTATIVES

**Michael Desselle (Co-Chair)**

Director- Public Policy  
American Electric Power  
1616 Woodall Rodgers Freeway  
Dallas, TX 75202-1234  
Phone: 214-777-1826  
Fax: 214-777-1831  
Email: [mddesselle@aep.com](mailto:mddesselle@aep.com)

**Lou Oberski**

Director, Electric Market Policy  
Dominion Resources Services, Inc.  
120 Tredegar Street  
Richmond, VA 23219  
Phone: 804-787-5714  
Fax: 804-787-6473  
Email: [lou\\_oberski@dom.com](mailto:lou_oberski@dom.com)

**Barry Green**

Manager, U.S. Regulatory Affairs  
Ontario Power Generation  
700 University Avenue, H18 G3  
Toronto, Ontario M5G 1X6 Canada  
Phone: 416-592-7883  
Fax: 416-592-8519  
Email: [barry.green@opg.com](mailto:barry.green@opg.com)

**Mary Ellen Paravalos**

Manager ITC Development  
National Grid USA  
25 Research Drive  
Westborough, MA 01582  
Phone: 508-389-3233  
Fax: 508-389-3129  
Email: [mary.ellen.paravalos@us.ngrid.com](mailto:mary.ellen.paravalos@us.ngrid.com)

**Charles H. Yeung**

Director, Business Standards Asset  
Commercialization  
P.O. Box 286  
Houston, TX 77001-0286  
Phone: 713-207-2935  
Fax: 713-207-9172  
Email: [cyeung@reliant.com](mailto:cyeung@reliant.com)

**Syd Berwager**

Industry Restructuring Project Manager  
Bonneville Power Administration  
Phone: 503-230-5958  
Fax:  
Email: [sdberwager@bpa.gov](mailto:sdberwager@bpa.gov)

**John A. Anderson**

Executive Director  
Electricity Consumers Resource Council  
1333 H Street, NW  
8<sup>th</sup> Floor, West Tower  
Washington, DC 20005  
Phone: 202-682-1390  
Fax: 202-289-6370  
Email: [janderson@elcon.org](mailto:janderson@elcon.org)

**NORTH AMERICAN ENERGY  
STANDARDS BOARD (NAESB) —  
Alternates****Edward J. Davis**

Policy Consultant  
Entergy Services Inc.  
P.O. Box 61000, L-MOB-18E  
New Orleans, LA 70161  
Phone: 504-310-5884  
Fax: 504-310-5477  
Email: [edavis@entergy.com](mailto:edavis@entergy.com)

**Tony Reed**

Project Manager  
Southern Company Services  
600 North 18<sup>th</sup> Street/GS-8260  
Birmingham, AL 35203  
Phone: 205-257-7766  
Fax: 205-257-6824  
Email: [tareed@southernco.com](mailto:tareed@southernco.com)

**Alan R. Johnson**

Manager, Business & Reliability Standards  
Mirant Corporation  
1155 Perimeter Center West  
Atlanta, GA 30338  
Phone: 678-579-3108  
Fax: 678-579-7726  
Email: [alan.r.johnson@mirant.com](mailto:alan.r.johnson@mirant.com)

**Andy Dotterweich**

General Supervisor-Federal Regulatory  
Affairs  
Consumers Energy Company  
One Energy Place  
Jackson, MI 49201  
Phone: 517-788-0495  
Email: [acdottweich@cmsenergy.com](mailto:acdottweich@cmsenergy.com)

**Tom Ringenbach**

Manager, Business Standards  
American Electric Power Service Corp.  
Phone:  
Fax:  
Email: [tringenbach@aep.com](mailto:tringenbach@aep.com)

**John P. Hughes**

Director of Technical Affairs  
Electricity Consumers Resource Council  
1333 H Street, NW  
West Tower, 8<sup>th</sup> Floor  
Washington, DC 20005  
Phone: 202-682-1390  
Fax: 202-289-6370  
Email: [jhughes@elcon.org](mailto:jhughes@elcon.org)

**Jim Templeton**

Principal  
Comprehensive Energy Services  
Phone:  
Fax:  
Email: [jrtmplton@aol.com](mailto:jrtmplton@aol.com)

**ISO/RTO Council Representatives****Karl Tammar — Co-Chair**

NYISO  
3890 Carman Road  
Schenectady, NY 12309  
Phone: 518-356-6205  
Fax: 518-356-6118  
Email: [ktammar@nviso.com](mailto:ktammar@nviso.com)

**James Detmers**

CAISO  
151 Blue Ravine Road  
Folsom, CA 95630  
Phone: 916-351-2123  
Fax: 916-351-2350  
Email: [jdetmers@caiso.com](mailto:jdetmers@caiso.com)

**Kent Saathoff**

ERCOT  
2705 West Lake Drive  
Taylor, TX 76574  
Phone: 512-248-3011  
Fax: 512-248-6560  
Email: [ksaathoff@ercot.com](mailto:ksaathoff@ercot.com)

**Bill Limbrick**

IMO  
Station A, Box 4474  
Toronto, Ontario M5W 4E5  
Canada  
Phone: 905-855-6293  
Fax: 905-855-6471  
Email: [bill.limbrick@theimo.com](mailto:bill.limbrick@theimo.com)

**Richard Wodyka**

PJM  
955 Jefferson Avenue  
Norristown, PA 19403  
Phone: 610-666-8860  
Fax: 610-666-4286  
Email: [wodykara@pjm.com](mailto:wodykara@pjm.com)

**IRC Alternates****Dale McMaster**

AESO  
1800, 700-4<sup>th</sup> Avenue, SW  
Calgary, Alberta T2P 3J4  
Phone: 403-705-5202  
Fax: 403-543-0388  
Email: [dale.mcmaster@aeso.ca](mailto:dale.mcmaster@aeso.ca)

**Steve Whitley**

ISO-NE  
One Sullivan Road  
Holyoke, MA 01040-2841  
Phone: 413-535  
Fax: 413-540-4226  
Email: [swhitley@iso-ne.com](mailto:swhitley@iso-ne.com)

**William Phillips**

MISO  
701 City Center Drive  
Carmel, IN 46032  
Phone: 317-249-5420  
Fax: 317-249-5703  
Email: [wphillips@midwestiso.org](mailto:wphillips@midwestiso.org)

**Carl Monroe**

SPP

415 North McKinley

Suite 800

Little Rock, AK 72205

Phone: 501-664-0146

Fax: 501-664-1809

Email: [cmonroe@spp.org](mailto:cmonroe@spp.org)

**Secretary****Gerry Cauley**

Director-Standards

North American Electric Reliability Council

116-390 Village Boulevard

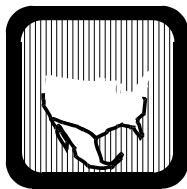
Princeton, NJ 08540

Phone: 609-452-8060

Fax: 609-452-9550

Email: [gerry.cauley@nerc.net](mailto:gerry.cauley@nerc.net)





## NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

### NERC-NAESB-ISO/RTO Council Joint Interface Committee Meeting

February 18, 2004 — 1:00 p.m.–5:00 p.m.

February 19, 2004 — 8:00 a.m.–4:00 p.m.

Wyndham New Orleans at Canal Place  
100 Rue Iberville  
New Orleans, LA 70130

### Meeting Minutes

#### Attendance

##### *NAESB Representatives*

Michael Desselle (Co-chair)  
John Hughes (alt)  
Syd Berwager  
Lou Oberski  
Charles Yeung (phone)  
Ed Davis (alt)  
Andy Dotterweich (alt)  
Alan Johnson (alt)  
Jim Templeton (alt)  
Mary Ellen Paravalos  
Tony Reed (alt)

##### *NERC Representatives*

Linda Campbell (Co-chair)  
Mark Fidrych  
Scott Henry  
Sam Jones  
Ed Schwerdt  
Ed Tymofichuk

##### *IRC Representatives*

Karl Tammar (Co-chair)  
Rich Wodyka (phone) – PJM

Kent Saathoff (phone)

##### *Other*

Tim Gallagher — Secretary

##### *Guests*

Steve Cobb — SRP  
Veronica Thomason — NAESB  
Bradley Kranz — NYISO  
Barbara Rehman — BPA  
Bill Boswell — NAESB  
Bruce Balmat (phone) — PJM  
Don Benjamin — NERC  
Rae McQuade — NAESB  
Todd Oncken — NAESB  
Marv Rosenberg — FERC  
Terry Bilke (phone) — MISO  
Marcel Harvey — TransEnergie  
Ken Brown (phone) — PSE&G  
Steve McCoy (phone) — CAISO  
Sandy Murrey (phone) — WE Energies

1. All present and those attending via teleconference were introduced. Transcripts of JIC meetings will be kept and a transcriber attended this meeting.
2. The agenda was unanimously approved. Todd Oncken reviewed the anti-trust guidelines. A quorum was established for NAESB, NERC, and ISO/RTO Council (IRC) members.
3. Michael Desselle presented an overview of the memorandum of understanding (MOU) between NAESB, NERC, and the IRC. The agreement creates a forum for coordination of annual planning and also establishes a mechanism for the review of proposals for standards and their subsequent assignment to either NAESB or NERC for development.
4. Michael Desselle reviewed the role of the JIC and its voting procedures. Each contingent of the JIC receives an equal share of the vote, divided by the number of representatives present. Since a quorum was established for all three JIC contingents at this meeting, each received one-third of the vote.
5. Lou Oberski presented three proposals for business practice standards received by NAESB.
  - Adopt already existing FERC OASIS business practice standards as NAESB standards. Doing so will provide NAESB with a starting point to initiate any changes requested by the industry via their standards development process (r04005).
  - Acceptance of the NAESB IT subcommittee's recommended actions on the OASIS IA issues left over from the OASIS scheduling collaborative (r04006).
  - Review existing OASIS standards and FERC Commission proceedings to develop a body of business practice standards for consideration as part of OASIS phase 2 (r04007).

**Motion (Lou Oberski, Andy Dotterweich second):** Assign development of the three business practice standards proposals (requests r04005, r04006, r04007) to the NAESB process.

**Discussion:**

Terry Bilke stated that the timing table included in r04005 for long term firm does not appear consistent with some Midwest ISO (MISO) transmission providers who need to perform impact studies. If this standard will become a mandatory requirement, the MISO would like more than 30 days to review the standard.

Alan Johnson stated that his NAESB subcommittee is aware of this concern and has assignment to follow up with MISO and Terry Bilke. [\[Action Item\]](#)

Marv Rosenberg questioned if the proposal was different than the current FERC requirements and was answered that no changes were intentionally made.

Mark Fidrych requested that NAESB develop a more user-friendly way of designating the requests, as the numbering system does not convey the intent of the standard. Lou Oberski will bring this up at future NAESB meetings.

**Vote:**

IRC — Unanimous approval of Mr. Oberski's motion

NAESB — Unanimous approval of Mr. Oberski's motion

NERC — Unanimous approval of Mr. Oberski's motion

**Motion carries**

6. Discussion of annual plans:

Lou Oberski presented an overview of the 2004 NAESB annual plan and the process used to develop and approve it. Linda Campbell asked for more information regarding the effort to coordinate the NAESB and NERC gas/electricity interdependency groups. Mr. Oberski agreed that such coordination is important and believes that the proper outreach will occur. There is a common NERC-NAESB task force member who can be enlisted as a liaison between the two groups.

Tim Gallagher presented an overview of the 2004 NERC annual plan and the process used to develop and approve it. Questions were raised about the implementation of the functional model and if the model was still a work in progress. Mr. Gallagher and Don Benjamin answered that the model will continue to be in a state of flux for the near future. A plan for certification of entities in the functional model and to transition to the model via the retirement of existing NERC requirements and their replacement by reliability standards is being developed. NAESB is represented on the team developing the transition plan.

Linda Campbell asked the group to focus not just on coordination of standards development, but also the coordination of their implementation. Michael Desselle stated that Linda's observation is an excellent one and is one that NERC, NAESB, and the IRC must work together to accomplish.

Karl Tammar presented an overview of the 2004 IRC annual plan and the process used to develop and approve it. The IRC pledges to work together with NERC and NAESB and builds upon activities included in their respective annual plans.

Scott Henry asked if any advancements made associated with reliability-related IT communications would be made available to non-RTO transmission providers. Further, will such communications improvements be submitted to NERC as standards?

Karl Tammar answered yes, in both cases. The IRC does not envision development of proprietary reliability related systems or data exchanges.

Michael Desselle asked if IRC/EPRI are coordinating CIMs (common information model) development with NERC? Mr. Desselle reminded the NAESB JIC representatives to follow this effort and any extensions to include market data.

Mark Fidrych stated that the same IRC representatives working on CIMS development are also involved in NERC's CIMs involvement. Because CIMs may be higher priority to IRC than NERC, Mr. Fidrych will propose that the NERC Operating Committee focus some attention upon the CIMs effort at its next meeting. Mr. Fidrych and Mr. Tammar will coordinate NERC and IRC efforts on CIMs development. [\[Action Item\]](#)

7. Steve Cobb presented an overview of a list of seams issues between RTOs and ISOs ("seams catalogue") developed by the NAESB Seams Subcommittee. Mr. Cobb explained that the goal of this effort was to identify seams issues across North America and who should work to resolve them. It is recognized that the catalogue does not contain all seams issues and that more may be added in the future. Later, any interested party can propose standards and the JIC can review and assign them to the appropriate organization for development.

Mr. Cobb stated that NAESB, NERC, and the IRC agreed which organization should be designated for the development of solutions to identified seams issues in the majority of cases.

**Discussion:**

Terry Bilke stated that the MISO was concerned about the potential for circumventing the development processes of NERC and NAESB via assignment made in the seams catalogue. Michael Desselle and Steve Cobb answered that it is not the intent of the catalogue or the seams subcommittee for any circumvention to occur. The catalogue and any assignment made in it do not preclude anyone from submitting a request for a standard to NAESB or NERC.

Karl Tammar stated that the IRC requests that four specific issues be put on hold, listed as regional, and that their development be assigned to the IRC:

1. Congestion management, (issues 35–36) LMPs at borders, and coordination of FTRs and other hedging mechanisms. These issues have policy, market design, and regional components.
2. Compensation for reactive power (16)
3. Issue 46, generator interconnection requirements, should not be an issue considered for standardization based upon prior agreement and FERC discussions.
4. Description of green power (113) needs clarification. If the intent of this issue pertains to market design, this should be a regional issue, assigned to IRC.

The JIC began a discussion of the items listed by Mr. Tammar and quickly came to the realization that the JIC cannot agree which organization should be designated as the developer for the referenced standards. The JIC agreed that similar discussion of other seams issue for which an agreed upon designated organization does not exist will not bear fruit either. Further, the JIC agreed that the designation in the seams catalogue carries no weight, other than to provide someone interested in proposing a given standard with an indication of which organization (NAESB, NERC or the IRC) should be approached.

**Motion: Mark Fidrych, Tony Reed second, friendly amendment by Scott Henry:** Accept those issues for which there is agreement for assignment of development of a standard proposal to the designated organization.

**Vote:**

IRC — Unanimous approval of Mr. Fidrych's motion

NAESB — Unanimous approval of Mr. Fidrych's motion

NERC — Unanimous approval of Mr. Fidrych's motion

**Motion carries**

**Motion: Lou Oberski, Mark Fidrych:** Accept the remaining seams issues and label the designated organization column as undecided.

**Vote:**

IRC — Unanimous approval of Mr. Oberski's motion

NAESB — Unanimous approval of Mr. Oberski's motion

NERC — Unanimous approval of Mr. Oberski's motion

**Motion carries**

Mike Desselle stated, and the JIC agreed, that no further action would be taken on any of the seams issues, until an interested party develops a request for an associated standard.

Ed Tymofichuk asked if the present seams catalogue adequately captures all the seams issues and what process will be used to incorporate seams issues identified in the future. Lou Oberski stated that NAESB could open collection of seams issues again and gather more, following a similar process used to solicit and collect the issues in the current catalogue. Perhaps a review of the most current catalogue could be placed on the JIC agenda on a routine basis.

8. The next two JIC meetings will be held as conference calls on May 18, 2004 at 2–3 p.m. central and July 13, 2004 from 2–3 p.m. central.

The next face-to-face JIC meeting will be held on September 21, 2004 at a location to be determined. The purpose of the meeting will be to discuss draft annual plans for 2005.

## Seams Catalog Column Headings:

---

- A Original Number** - The number originally assigned the seam issue. Used to track each issue as it was categorized and re-categorized.
- B Category** - Seam issues are grouped into one of 8 categories:
1. Congestion Management
  2. Market Design
  3. Market Monitoring / Compliance
  4. Market Standards
  5. Planning
  6. System Reliability
  7. Transaction Scheduling
  8. Transmission Service
- C 1st Sub-Category** - The seam issues categories are further delineated into 1st sub-categories.
- D 2nd Sub-Category** - The seam issue 1st sub-categories are even further delineated into 2nd sub-categories.
- E Description Of Seam Issue** - Brief description of the seams issue.
- F Comments** - Additional comments providing background or further definition of the seam issue.
- \* Association / Notes** - Identification of associated seam issues based on their Original Number. (Ed. Note: this column was eliminated once seams issues were categorized).
- \* Seam Interface Type** - Each seam interface has 2 acting parties. Here the market status relationship between the 2 acting parties are identified, e.g., RTO Market to RTO Market, RTO Market to Non-RTO Market, Non-RTO Market to Non-RTO Market. (Ed. Note: this column was eliminated once seams issues were categorized).
- G Resp Org Cobb** - Recommended assignment by Steven Cobb, Salt River Project.
- H Resp Org IRC** - Recommended assignment by Karl Tammar, NYISO, as representative of the IRC.
- I Resp Org Mueller** - Recommended assignment by Ken Brown and Jeff Mueller, PSEG.
- J Resp Org WEQ EC** - Recommended assignment by WEQ EC for JIC meeting held on Feb. 18-19, 2004.
- K NERC Choice** - Recommended assignment by NERC for JIC meeting held on Feb. 18-19, 2004. Not part of the WEQ Seams Subcommittee's work product. Included for informational purposes only.
- L Issue Type** - Categorization of seams issue as either "national" or "regional" in scope.
- M Responsible Organization JIC** - The recommended organization as assigned by the NERC / NAESB / IRC Joint Interface Committee (JIC) at meeting held on Feb. 18-19, 2004.
- L Region 1** - The RTO, ISO, or Non-RTO Market Region that is the 1st acting party to the seam issue is identified here.
- M Region 2** - The RTO, ISO, or Non-RTO Market Region that is the 2nd acting party to the seam issue is identified here.

### **Seams Catalog Column Headings:**

---

- N**    **Priority** - The organization assigned a seam by the NERC / NAESB / IRC Joint Interface Committee (JIC) will use this column to prioritize their efforts.
- O**    **Seam Impediment Type** - Identification of what causes the seam issue, e.g., market rule, business practice, physical barrier.
- R**    **Currently Being Addressed** - Identification of another body that is currently working on the seam issue.
- S**    **Submitter** - The name of the person and organization providing the matrix information.
- T**    **Reference Papers** - If reference papers are provided to support the information, a letter is assigned to the document. The index of reference papers appears at the end of the matrix.
- U**    **NAESB Support** - Comments of WEQ EC in support of their recommendations contained in column J. Not part of the actual catalog adopted by the EC or JIC. Included for informational purposes only.

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
36	Congestion Management	Congestion Management Market Coordination	Coordinate Hedging Instruments at Market Interfaces	Coordination of market based congestion hedging instruments, such as FTRs, between adjacent RTOs with markets, especially for out and thru' transactions		National	Undecided	
132	Congestion Management	Congestion Management Market Coordination	Joint Re-Dispatch Agreements	Interaction with American Transmission Company; possible joint redispatch agreement among ATC-PJM-Generators on ATC's system		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
115	Congestion Management	Congestion Management Market Coordination	Standardize Congestion Management Market Data Exchange	Congestion Management Procedures including reciprocal coordination agreement, exchange of data for real-time and projected operations, SCADA, EMS, Operations Planning and Planning information and models; better granularity, avoid double counting, use of state estimator and LMP to enable RTOs to accurately and consistently quantify flows/impacts outside of NERC IDC to enable RTO to RTO and market to market congestion management to achieve greater efficiencies without calling TLRs; MISO and PJM and expansions to use same methods.	Definition of AFC coordination process between RTOs.	Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
35	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Locational Marginal Prices (LMP) at borders of RTOs with markets (Price cap included)		National	Undecided	
68	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Prior to Day Ahead. Secondary Market	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent prices at the boundaries? If not, can price discontinuities be tolerated or managed? (Issue I.b.1)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
70	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Congestion Management Market	If models with identical levels of detail for the West are not used by all three RTOs, do the various simplifications for areas outside any given RTO create problems in achieving a uniform set of redispatch prices? (Issue I.b.3)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
72	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Model spatial granularity	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent day ahead prices at the boundaries? (Issue I.b.5)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
80	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Other Scheduling Requirements	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent prices at the boundaries that send the same signal to the market? If not, can price discontinuities be tolerated or managed? (Issue I.b.13)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group



**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
92	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Real Time. Model objective function	How much would a common dispatch interval mitigate against price discontinuities at boundaries? (Issue I.d.2)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
62	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Financial or Physical	Must the offerings be identical? How can congestion management discontinuities be mitigated? (Issue I.a.3)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
63	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Option or Obligation	Do different CM models create barriers to trade, and if so, how can these differences be mitigated? (Issue I.a.4)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
64	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Revenue Stream/ or Offset CM Cost	Must the term of congestion offerings be identical? How can congestion management discontinuities be mitigated? (Issue I.a.5)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
129	Congestion Management	Congestion Management Market Coordination		Selection process for market/TLR coordinated flowgates; inclusion of flowgates in PJM FTR/ARR auctions; flowgates with and without effective control by markets; updates to flowgate list, phase-in; dispute resolution; let RTO calculate flows outside of IDC and TLR; audit rights; confidentiality of data; consideration of flowgates outside PJM and MISO	Standardized rules for determining flowgates impacted by an RTO.	Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
138	Congestion Management	Congestion Management Market Coordination		Coordination of congestion	Several regional efforts are underway. Coordinate practices and methods between areas with different market approaches.	National	NAESB	Yes
125	Congestion Management	Determining Control Area Boundaries		Retention of former CAs in the model	When expanding Control Area boundaries (i.e., merging Control Areas) is it necessary to retain "Historic" boundaries for use in NNL estimation or other reasons?	Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
73	Congestion Management	Operate Markets Within Transmission Limits		Market Design - Day Ahead. Model objective function	Who coordinates the scheduling constraints (i.e., security constrained dispatch) on paths that cross RTO boundaries to ensure that inter-RTO schedules do not exceed reliability standards? (Issue I.b.6)	Regional	Undecided	SSG-WI, CMA Work Group
130	Congestion Management	Operate Markets Within Transmission Limits		What happens when MISO and PJM and outside PJM/MISO firm and CBM exceed TTC - day ahead mechanism to reduce oversubscribed conditions		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
43	Congestion Management	Standardize and Coordinate ATC Calculations	Contract Tie Capacity Sharing	Allow Sharing Contract Tie Capacity between Entities across Seams	Lack of Coordination and Sharing of Tie Capacity is an artificial market barrier	National	Undecided	Limited

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
59	Congestion Management	Standardize and Coordinate ATC Calculations	Coordinate Hedging Instruments at Market Interfaces	Inter-control area congestion management / parallel flow management	Develop congestion hedges across control area boundaries.	Regional	NYISO/ISO-NE	Northeast ISO
44	Congestion Management	Standardize and Coordinate ATC Calculations	Standardize TRM and CBM Calculations	Calculation and Values of TRM and CBM consistent	Underutilization of Transmission Capacity	National	NERC	Limited
17	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission Markets	TTC-ATC calculation/posting	Interface between a financial market (no physical transmission arrangements) and physical transmission regions (selling transmission capacity through OASIS reservations): Problems of TTC-ATC calculations coordination. Counterparties include IMO, NYISO, and ISO-NE.	Regional	Undecided	No
61	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission Markets	Market Design - Prior to Day Ahead. Congestion Revenue Rights (CRRs) [Firm Transmission Rights (FTRs) in MD02, FTOs in RTO West]	Are all transmission rights both physical and financial required to be identical to mitigate the seams problems? (Issue #1.a.2)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
9	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Transmission Calculations	Transmission calculations are not consistent. Solution: Standardized ATC Calculations.	National	Undecided	Yes - SSG - WI
55	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Improved TTC/ATC posting	Monthly and yearly posting of TTC/ATC values to support transaction pre-scheduling. Clarify how the ATC values calculated by each ISO should be used to ascertain the ability of the interface to support transactions.	Regional	Undecided	Northeast ISO
109	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		ATC Differences - Individual control areas determine ATC for jointly operated transmission interfaces. Differences in ATC calculations can confuse the marketplace, which may react by avoiding transactions that would otherwise be economic due to the uncertainty and perceived risk.		Regional	Undecided	In Northeast Power Markets Seams Action Plan
116	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		ATC/AFC Coordination - MISO and PJM to coordinate with any external parties wishing to do so, respecting all significant flowgates external to their respective boundaries; availability and levels of service and curtailments for firm and non-firm, network and point to point.		Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
20	Congestion Management	Standardize TTC Calculations Across Interfaces		TTC coordination	Disagreement between two operators on the physical capability of an interconnection (line 7040 and Phase II). Counterparties are NYISO and ISO-NE.	National	NERC	Yes

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
69	Congestion Management	System Market Modeling Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Energy Spot Market	In order to achieve a uniform set of redispatch prices, if that is necessary, do the network models have to be identical, with the exact system? Each time each one is used does it have to be synchronized with the other RTOs or is a single process required? In addition do the programs that use the models have to be identical in order to get the uniform set of redispatch prices? (Issue I.b.2)	Regional	Undecided	SSG-WI, CMA Work Group
47	Congestion Management	System Market Modeling Coordination		Operational Model Updates	Areas must have up to date models for operational use of other areas across the seam	National	NERC	Limited
75	Congestion Management	System Market Modeling Coordination		Market Design - Day Ahead. Model objective function	Does the use of both AC and DC OPFs introduce compatibility problems? (Issue I.b.8)	Regional	Undecided	SSG-WI, CMA Work Group
121	Congestion Management	System Market Modeling Coordination		Market flow data - reflect ISN and SDX data	Standardize inputs to estimation of power flows (i.e., GLDFs, outages, etc...).	Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
123	Congestion Management	System Market Modeling Coordination		GDLF calculation	Standardized methodology for determining distribution factors - standard OPF model for each interconnection?	Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
135	Congestion Management	System Market Modeling Coordination		Historic NNL values should not be reflected indefinitely in the future, and an appropriate mechanism to rationalize the historic flows to recognize eventual market conditions should be developed		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
133	Congestion Management	Transmission Market Design	Redispatch of Generation	Define "RTO area wide dispatch"	AJR - This refers to centralized dispatch across a RTO Footprint, rather than within a CA Boundary.	Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
110	Congestion Management	Transmission Market Design	Transmission Market Manipulation	ATC Manipulation - Market participants schedule transactions day-ahead and beyond with no intent to deliver energy. Cancellation in real-time by a market participant results in unused ATC, ramp capability that cannot be used by other market participants. Valuable capability is left unused.		Regional	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan
53	Congestion Management	Transmission Market Design	Transmission Service Product Type Priority	CAISO ETC rights scheduling - Contract Reference Number	CAISO uses Contract Numbers to track ETC rights. This causes Phantom Congestion and does not allow ETC rights holders to sell and schedule their transmission	Regional	Western Interconnect SSG-WI	No
88	Congestion Management	Transmission Market Design	Transmission Service Product Type Priority	Market Design - Day Ahead. Centralized Unit Commitment.	Does a recallable physical right conflict with a redispatch set in a day-ahead clearing process? (Issue I.b.21)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
98	Market Design	Energy Market Design and Coordination	Demand Side Energy Market Coordination	Market Design - Post Real Time. Settlement stages	How does bidding or demand-side response between or among RTO's affect the scheduling and dispatch of obligations within the RTO's? Can these kinds of trades between RTOs be accommodated? Does trade of these services between RTOs have implications for either the exporting or importing RTOs ability to meet reliability criteria? (Title to power needs to be established) (Issue II).	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
90	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Hour Ahead. Timing	How does hour-ahead market integrate with neighbors who do not have hour-ahead process? (Issue I.c.2)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
91	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Hour Ahead. Energy Market, Congestion Management Market, and Ancillary Services Market	Is it necessary to align real time markets? If so, can a method be developed to produce consistent real-time prices at the boundaries? (avoid an price discontinuity due to separate calculation of prices with different information.) (Issue I.d.1)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
93	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Real Time. Dispatch interval	Can a method be developed to produce consistent real-time prices at the boundaries? (avoid an price discontinuity due to separate calculation of prices with different information.) If not, can discontinuities be tolerated or managed? [This may be more of a settlements issue than a consistency issue.] (Issue I.d.3)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
131	Market Design	Energy Market Design and Coordination		Express sunset provisions for implementation of Day 2 markets		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
113	Market Design	Green Power Market		Green power attributes trading		National	Undecided	In Northeast Power Markets Seams Action Plan
96	Market Design	Market Settlement Systems	Energy Market Settlement Process at Market Interfaces	Market Design - Real Time. Penalties	Do settlement systems have to be common as long as price discontinuities at the boundaries are managed? (Issue I.e.1)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
97	Market Design	Market Settlement Systems	Energy Market Settlement Process at Market Interfaces	Market Design - Post Real Time. Settlement stages	How are inter-RTO settlements managed? (Includes the revenue adequacy issues related to achieving consistent prices.) (Issue I.e.2)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
86	Market Design	Transmission Ancillary Service Market Design and Coordination	Ancillary Service Auction Coordination	Market Design - Day Ahead. Ancillary Service Market	All three propose auctions: Do the auctions have be identical? Is it possible to use price exchange (say as imputed bids) in connection with interactive calculation to minimize the spread between the A/S auctions? (Issue I.b.19)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
81	Market Design	Transmission Ancillary Service Market Design and Coordination	Ancillary Service Prices at Market Interfaces	Market Design - Day Ahead. Congestion Prices.	Can a "best practice" model for definition and acquisition of ancillary services products be developed to produce consistent prices at the RTO boundaries? (Issue I.b.14)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
16	Market Design	Transmission Ancillary Service Market Design and Coordination	Reactive Power Compensation	Compensation for Reactive Power	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	National	Undecided	Yes / IIPTF
85	Market Design	Transmission Ancillary Service Market Design and Coordination	Transmission Service Requirements for Ancillary Service Delivery	Market Design - Day Ahead. Ancillary Service Market	Does the RTO of the A/S seller recognize the transmission capacity reservation required to enable the reserves to respond for outages in the RTO of the buyer? (Issue I.b.18)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
74	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Model objective function	What is the effect of linking energy and ancillary service markets in the optimizations on model coordination issues? (Issue I.b.7)	Regional	Undecided	SSG-WI, CMA Work Group
83	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Ancillary Service Market	When ancillary services are provided from within one RTO for another RTO, does the providing RTO recognize them as obligations within the seller's RTO? (Issue I.b.16)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
84	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Ancillary Service Market	How can AS bids be coordinated across three markets to avoid both double counting and inefficient limitations on bids? (Issue I.b.17)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
87	Market Design	Unit Commitment Procedure Standardization		Market Design - Day Ahead. Acquisition Mechanism	Does unit commitment need to be standardized? Is this an area where each RTO can have its own method, which matches its resource mix and system responsiveness? (Rapid response of hydro gen. versus lead time requirements for thermal gen.) (Issue I.b.20)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
13	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Unscheduled Flows of Electricity	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	National	Undecided	Yes / IIPTF

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
15	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Loop Flow	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	National	Undecided	Yes / IIPTF
29	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Allocation of transmission capacity on reciprocal flow gates amounts to transmission service without compensation. Legitimizes "parallel loop flow".		National	Undecided	
66	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Market Design - Prior to Day Ahead. Duration	How will rights for loop flows (non-contract flows) in other RTOs be allocated/acquired? (Issue I.a.7)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
134	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for parallel flows		National	NAESB	In PJM/MISO Congestion Management Proposal Whitepaper
142	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Pricing for native load loop flow impacts		Regional	Multiple	No
77	Market Monitoring/ Compliance	Anti-Gaming Coordination		Market Design - Day Ahead. Schedule Components	Will different RTO congestion management systems enhance opportunities for gaming or affect generation dispatch efficiency? (Issue I.b.10)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
11	Market Monitoring/ Compliance	Market Monitoring Entity Requirements		Market Oversight	New and mature markets need oversight to ensure that existing rules are complied with and new rules are adequate in meeting the scenarios they were designed to govern. Solution: Independent Market Auditor or Monitor.	Regional	Multiple	Yes - SSG - WI
94	Market Monitoring/ Compliance	Penalty/Sanction Coordination		Market Design - Real Time. Imbalance Price	Do penalties need to be the same in each RTO? (Issue I.d.4)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
95	Market Monitoring/ Compliance	Penalty/Sanction Coordination		Market Design - Real Time. Penalties	Will inconsistent imbalance penalty practices hamper non-dispatchable resource sales across RTO boundaries? (Issue I.d.5)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
3	Market Standards	Energy Market Standard Product Definitions		Definition & treatment of Firm/nonfirm Power	Annual Plan Item 4ci moved from MOS	National	Undecided	No
10	Market Standards	Energy Market Standard Product Definitions		Energy Products	Entities have disagreements concerning the definitions of various energy products. Solution: Standardized Energy Products.	National	NAESB	Yes - WECC

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
25	Market Standards	Energy Market Standard Product Definitions		Need for common physical market and products - regional variations permitted		National	NAESB	No
34	Market Standards	Energy Market Standard Product Definitions		Clarification of Product Definitions	Complete/Standard definitions for Liquidated Damages (LD), "Into", etc.	National	NAESB	No
139	Market Standards	Energy Market Standard Product Definitions		Standard definition of energy products	Energy products and services have common attributes in all markets. Standards definitions will improve efficiencies in communicating and operating between areas with various market designs	National	NAESB	Yes
7	Market Standards	Market Standard Communication Protocols and Transparency		Market Price Information	Market pricing methodology not comprehensive, consistent or dependable. Solution: Standardized Indices, Independently Managed.	Regional	Western Interconnect	No
42	Market Standards	Market Standard Communication Protocols and Transparency		Data Visibility	Inability to view neighboring markets information through a common software such that this sometimes hinders Market Participants ability to complete business in a timely fashion.	National	NAESB	Yes
52	Market Standards	Market Standard Communication Protocols and Transparency		Confidentiality of Data and Information Shared	Standards of Confidentiality would enhance the capability to resolve data sharing and information posting	National	NAESB	Limited
71	Market Standards	Market Standard Communication Protocols and Transparency		Market Design - Day Ahead. Model spatial granularity	To what extent do RTOs need to see other RTOs' scheduling information? (Issue I.b.4)	Regional	Undecided	SSG-WI, CMA Work Group
140	Market Standards	Market Standard Communication Protocols and Transparency		Standard messaging protocols for market notifications	Market participants will benefit from common messaging protocols.	National	NAESB	No
1	Market Standards	Market Standard Operating Time		Non Standard Time Zone	The lack of a standard Time Zone causes Market Inefficiencies	National	NAESB	No
136	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	There is a disconnect between the timing of bids and offers in the Ontario market and the releasing of firm transmission in MISO for which schedules have not been submitted for use as non-firm transmission.	Regional	Undecided	No
137	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	Timing issues between bid based markets (one example only - not knowing whether your bid has been accepted in "sink" market before having to commit in the "source" market).	Regional	IMO/NYISO	No
14	Market Standards	Physical and/or Financial Resolution of Inadvertent Interchange		Compensation for Inadvertent Interchange	Lack of compensation lessens incentives for operators to solve problems. Explicit compensation for inadvertent interchange is necessary for appropriate definition of other products, in that such compensation ensures that the defined product is delivered.	National	NAESB	Yes / IIPTF

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
111	Market Standards	Transmission Ancillary Service Market Design and Coordination	ICAP Market Standardization	Capacity Market - Differences in ICAP definitions, requirements, deliverability, and recall procedures have hampered the ability of suppliers to sell ICAP between Northeast ISOs (include regional resource adequacy model, external 30-minute reserves participation, harmonize demand response programs)		Regional	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan
46	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection - Affected Systems	Generation Interconnection Studies	Generation Interconnections close to seam affects both areas	National	Undecided	Limited
57	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection Transmission Requirements	Transmission interconnection procedures	Need consistent approach to treating merchant generation interconnection procedures with transmission	Regional	Multiple	Northeast ISO
114	Planning	Transmission Expansion and Generator Interconnection Coordination	Interregional Transmission Planning Procedures	Coordination of interregional planning including transmission facilities and generator interconnection procedures		Regional	Undecided	In Northeast Power Markets Seams Action Plan
26	Planning	Transmission Expansion and Generator Interconnection Coordination	Transmission Expansion Cost and Construction Responsibilities	Transmission expansion planning - coordination between systems and determine who is obligated to build and pay for improvements	Being reviewed by PJM/MISO.	Regional	Multiple	Yes
48	System Reliability	Emergency Operations	Computer Failures	Communication of Computer Failures	Needed for reliable operations and emergency operations	National	NERC	Limited
49	System Reliability	Emergency Operations	Emergency Operating Procedures for Market Interfaces	Emergency Procedures	Emergency procedures require operations across seams	National	NERC	Limited
128	System Reliability	Emergency Operations	System Monitoring and Contingency Plans	Contingency plans; critical path analysis		National	NERC	In PJM/MISO Congestion Management Proposal Whitepaper
118	System Reliability	Emergency Operations	System Restoration Procedures	Emergency and Restoration Plans - operating procedures for Voltage Collapse and Stability		National	NERC	Included in Attachment A of MISO and PJM Reliability Plans
122	System Reliability	Functional Model		Control area - control zone responsibilities vs. market operator		National	NERC	In PJM/MISO Congestion Management Proposal Whitepaper
50	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Schedule Ramp Management	Ramping standard differences across the seams hinder business	National	Undecided	Limited



**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
108	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Failure of Transactions due to Ramping of Control Area Interchange - Desirable transactions between control areas may be "blocked" from access to the grid due to insufficient dispatch capacity to absorb large schedule changes while maintaining energy/load balance within the control area.		Regional	Undecided	In Northeast Power Markets Seams Action Plan
51	System Reliability	Generation-Load Balance	Inter-Market Resource Requirements	Resource Adequacy	Parties in one area rely on resources in other areas. Validation of their reliance on the other area must be coordinated.	National	NERC	Limited
27	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Outage Maintenance Coordination	Being reviewed by PJM/MISO. See PJM presentation "Status Report to FERC on July 31, 2002 Alliance Order" dated Jan 2003, page 6 as posted under NAESB WEQ Seams subcommittee July 8 date	National	NERC	Yes
45	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Coordination of Transmission and Generation Outages	Both forced and planned outages	National	NERC	Limited
120	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Facilities in close electrical proximity under different RTOs - outage maintenance coordination, access and expansion planning		Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
30	System Reliability	Operate Markets Within Transmission Limits		Market allocations over flow gates are approved without regard to flow gate capacity resulting in over subscription of flow gates.		National	NERC	
99	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Demand Response Participation.	If there is an RTO capacity requirement for all RTOs, how will double-counting across RTOs be avoided? Note: RTO West and WestConnect are not currently proposing a resource adequacy requirement independent of the requirement for balanced schedules. (Issue X.1).	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
100	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Resource Adequacy. Resource Adequacy Assessment.	If there is an RTO capacity requirement for all RTOs, do different resource adequacy approaches result in different penalty structures and if so, does this create problems, e.g., opportunities for arbitrage? Note: RTO West and WestConnect are not currently proposing a resource adequacy requirement independent of the requirement for balanced schedules. (Issue X.2).	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
119	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	NERC Regional Criteria and Reserve Sharing - define operating policy changes, waivers, or certifications that are needed to permit security-constrained dispatch over multiple existing control areas to allow flows not to be tagged; Joint Reliability Coordination - NERC Policies 5 and 9		National	NERC	In PJM/MISO Congestion Management Proposal Whitepaper
82	System Reliability	Operating Reserves/Resource Adequacy	Reliability Aspects of Inter-Market Scheduling of Ancillary Services	Market Design - Day Ahead. Ancillary Service Market	How does bidding of ancillary services between or among RTOs affect the scheduling and dispatch obligations within the RTOs? Can this kind of trade between RTOs be accommodated? Does trade of these services between RTOs have implications for either the "exporting" or "importing" RTO's ability to meet reliability criteria? (Issue I.b.15)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
107	System Reliability	Transaction Curtailments	Market Impacts of Transaction Curtailments for Reliability Reasons	Transaction Curtailment - Transaction curtailments for security may extend beyond the reliability need due to differences in market timing. Extended curtailments are disruptive to both the marketplace and the reliable operation of the grid.		Regional	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan
126	System Reliability	Unscheduled/Parallel Path Flow Management	Interchange Distribution Calculator Requirements	Definition of coordination between market entity (PJM or MISO) and the IDC; define necessary changes to IDC; updates of base cases and book of flowgates		Regional	Undecided	In PJM/MISO Congestion Management Proposal Whitepaper
127	System Reliability	Unscheduled/Parallel Path Flow Management	Interchange Distribution Calculator Requirements	Industry oversight and reporting of PJM and MISO impact calculations - IDC cost, cost allocation to reimburse NERC		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
23	System Reliability	Unscheduled/Parallel Path Flow Management	Parallel Path/ Unscheduled Flow Monitoring and Operation	How different congestion management methodologies will interact to ensure parallel flows and impacts are recognized and controlled to ensure system reliability.	Being reviewed by PJM/MISO.	Regional	Undecided	Yes
24	System Reliability	Voltage Control		Voltage Operating Procedures	Being reviewed by PJM/MISO. See PJM presentation "Status Report to FERC on July 31, 2002 Alliance Order" dated Jan 2003, page 6 as posted under NAESB WEQ Seams subcommittee July 8 date	National	NERC	Yes
5	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Provision of reserves across multiple control areas	Annual Plan Item 4cii moved from MOS	National	NERC	No
39	Transaction Scheduling	Controllable Line Scheduling		Controllable Line Scheduling	Concept of operations for general methodology to schedule controllable lines between RTOs. Being reviewed by NYISO	Regional	Undecided	Yes

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
58	Transaction Scheduling	Controllable Line Scheduling		Controllable line scheduling	Concept of Operations for general methodology to schedule controllable lines has been drafted. A multi-ISO stakeholder group (similar to JCAG) needs to be formed to review the draft Concept of Operations to provide stakeholder input.	Regional	NYISO/ISO-NE	Northeast ISO
60	Transaction Scheduling	Controllable Line Scheduling		Cross-border price convergence	The lack of price convergence at the control area boundaries may inhibit the desire of market participants to arbitrage between neighboring markets. This issue is being referred to the individual ISO Market Committees for further definition on the business issue that needs resolution.	Regional	NYISO/ISO-NE	Northeast ISO
12	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Develop Electronic Scheduling	Interchange/Intrachange Scheduling Data Exchange	Current E-Tagging process is inadequate for exchanging reliability and market data within the Western Interconnection. Solution: Electronic Scheduling	National	NAESB	Yes - WECC
41	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Inter-Market Ramping Requirements Standardization	Scheduling Coordination (including Ramp Rates)	RTOs have different ramp rates and scheduling requirements that require Market Participants to complete multiple submissions for the same transaction.	National	Undecided	Yes
79	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Standardize Inter-Market Scheduling Timelines	Market Design - Day Ahead. Other Scheduling Requirements	Should the time intervals and submission times be synchronized to mitigate obstacles to inter-RTO trade? (Issue I.b.12)	National	NAESB	SSG-WI, CMA Work Group
78	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Tools and Procedures to Accommodate Inter-Market Interchange Scheduling Requirements	Market Design - Day Ahead. Schedule Components	Can tools be developed for scheduling submission that assist the user in meeting any differences in protocols between RTOs? (Issue I.b.11)	National	Undecided	SSG-WI, CMA Work Group
8	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Scheduling	Inconsistent procedures among entities. Solution: Western Interconnection Standardized Interchange Scheduling Protocols.	Regional	Multiple	Yes - SSG - WI
76	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Market Design - Day Ahead. Model objective function	Do differences in the scheduling requirements (e.g., requirements for balanced schedules) between RTOs create seams problems for inter-RTO schedules? If so, can these problems be mitigated? (Issue I.b.9)	Regional	Undecided	SSG-WI, CMA Work Group
104	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transmission Checkout Failure - Operators curtail transactions due to mismatched tag data, different MW volumes, etc. The curtailment of transactions due to data incompatibility is disruptive to both the marketplace and the reliable operation of the grid.		National	NAESB	In Northeast Power Markets Seams Action Plan

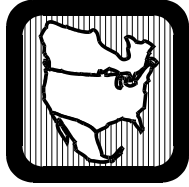
**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
106	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transaction Scheduling - Inconsistent information and market timing rules lead to uncertainty and risk that discourage the scheduling of some inter-regional transactions.		National	NAESB	In Northeast Power Markets Seams Action Plan
32	Transmission Service	Transmission Market Design	Transmission Service Product Type Priority	MISO- PJM market allocation will give preference to the market as Network over PTP even though the Market allocation may be a non paying transmission customer.		Regional	PJM/MISO	
40	Transmission Service	Transmission Market Standard Product Definitions and Priorities	Multiple Proxy Bus Development	Multiple Proxy Buses for Free Flowing Interfaces	Development of multiple proxy buses between RTOs for scheduling and pricing.	Regional	NYISO/ISO-NE/PJM	Yes
4	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Definition & treatment of Firm/nonfirm Transmission	Annual Plan Item 4cii moved from MOS	National	Undecided	No
103	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Transmission Service - Market participants require consistent treatment of transmission products across multiple control areas to reduce perceived market risk, scheduling confusion and uncertainty.		National	NAESB	In Northeast Power Markets Seams Action Plan
124	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Wide area dispatch and network resources to network loads - resource deliverability if not a firm network load		Regional	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper
141	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Replacement of contract path with flow-based transmission service		Regional	Multiple	No
54	Transmission Service	Transmission Service Pricing	Discounting of Market Interface Transmission ATC	Transmission service charge discounting	Ability for TOs to discount TSC rates on external interfaces to selectively reduce export charges and encourage use of ties. The software exists, however, there does not appear to be any business incentives to exercise discounts.	Regional	NYISO/ ISO-NE	Northeast ISO
22	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Rate pancaking elimination	Being reviewed by PJM/MISO.	Regional	PJM/MISO	Yes
38	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Rate Pancaking	Charges to Market Participants who conduct business over more than one RTO. Reciprocal agreements needed to eliminate these charges. NYISO and ISO NE	Regional	NYISO/ISO-NE	Yes
105	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Export Charges (Pancaking) - Control-area specific export charges remove incentives to transact business when transaction margins are of the same magnitude or less than the prevailing export charges. Such charges include transmission and ancillary service components.		Regional	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan

**Seams Issues Matrix**  
(As Adopted at JIC Meeting, Feb. 18-19, 2004)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org JIC	Currently Being Addressed
117	Transmission Service	Transmission Service Procurement	Common Reservation System for Market Interface Transmission ATC	Contract Tie Capacity - One Stop Shopping		Regional	NAESB	No
6	Transmission Service	Transmission Service Procurement	Common Western Interconnection Wide OASIS	Transmission Access	No transmission market one stop shopping available for the Western Interconnection - entities can't find needed information to efficiently conduct business on a preschedule or real-time basis. Solution: Common OASIS Site needed.	Regional	Undecided	Yes - Various Transmission Providers
89	Transmission Service	Transmission Service Procurement	Hour Ahead Transmission Service Market Standardization	Market Design - Day Ahead. Release of Unused Transmission Capacity after Close of DA Markets	How are boundary prices to be synchronized between RTO's if only one RTO has a hour ahead process? Is it necessary to align hour ahead markets? (Issue I.c.1)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
33	Transmission Service	Transmission Service Procurement	Intra-Hour Transmission Service Procurement	Standard for Purchasing of Intra-Hour Transmission	The ability to purchase transmission after the top of the hour when the transmission service is predetermined as available in prior hour.	National	NAESB	No
65	Transmission Service	Transmission Service Procurement	Long-Term Transmission Service for New Construction	Market Design - Prior to Day Ahead. Duration	To the extent that longer term transmission rights are needed for new construction, can agreement be reached to issue long term rights? (Issue I.a.6)	Regional	Western Interconnect SSG-WI	SSG-WI, CMA Work Group
67	Transmission Service	Transmission Service Procurement	Secondary Transmission Service Market Standardization	Market Design - Prior to Day Ahead. Primary Release Mechanism	There seems to be agreement here that a secondary market would be outside the RTO. If the resulting secondary market is not westwide, will coordination be needed? (Issue I.a.8)	Regional	Multiple	SSG-WI, CMA Work Group
112	Transmission Service	Transmission Service Procurement	Transmission Service for ICAP Market	Long-term Transmission Service Availability to Support ICAP Transactions - Firm transmission reservation requirements to establish "Deliverability" as a requirement to buy external ICAP results in an economic advantage for internal suppliers and a barrier to market entry for external suppliers.		Regional	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan
28	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Being reviewed by PJM/MISO.	National	NAESB	Yes
56	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Companies that conduct business across Control Area borders are faced with receiving a TSC bill from each TO. A single charge should be provided to each transaction to the appropriate parties and revenues allocated to the TOs according to the appropriate usage formulas.	Regional	NYISO/ISO-NE	Northeast ISO

#	Reference Paper or Supporting Document Provided
A	"Profit-Enhancing Seam Management: A White Paper on Pricing The Unscheduled Flows of Electricity Across the Seams Between Utilities Using A Geographically Differentiated Auction of Inadvertent Interchange", released 2001 March 25 (Mark Lively - Lively Utility).
B	"WOLF: Wide Open Load Following," A presentation to the NERC Market Interface Committee, 2002 September 4-5, Houston, Texas (Mark Lively - Lively Utility).
C	E-Mail by Mark Lively to NAESB WEQ Seams Subcommittee of 9/4/2003 8:28:10 PM Eastern Standard Time (Mark Lively - Lively Utility).
D	See the PJM/MISO JOA dated 8/5/03 (Linda Horn - WE Energies).
E	MISO - PJM Managing Congestion to Address Seam Paper, April 28, 2003 (Dave Nick - DTE Energy) (Ed. note: white paper updated Aug. 4, 2003).
F	<i>Intentionally left blank.</i>
G	Northeast ISOs Seams Resolution Report: History of Seam Issues Resolution (Jan. 15, 2003); and Ongoing Northeast ISOs "Seams" Projects, 2003-2004 (Jan. 14, 2003) (Joe Rossignoli - National Grid).
H	In Northeast Power Markets Seams Action Plan - October 9, 2002 and July 14, 2003, and July 3, 2003 timeline update (Jeff Mueller - PSEG).
I	Attachement A of MISO and PJM Reliability Plans (Jeff Mueller - PSEG).
J	MISO compliance filings in FERC Docket No. EL03-35-004 and in Whitepaper "Managing Congestion to Address Seams" PJM and MISO May 16, 2003 (Jeff Mueller - PSEG).
K	ATC's Attachment K (Jeff Mueller - PSEG).
L	M. Lively, Forcing Reserves to Compete with a Physical Market (2002) (Lou Oberski -- Dominion Energy).



## **NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL**

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

### **NERC-NAESB-ISO/RTO Council Joint Interface Committee Conference Call Minutes (Draft) June 24, 2004**

#### **Attendance**

##### **NERC Members/Alternates**

Linda Campbell, FRCC (Co-Chair)  
Scott Henry, Duke Power  
Sam Jones, ERCOT  
Ed Schwerdt, NPCC  
Gerry Cauley, NERC (Secretary)

##### **NAESB Members/Alternates**

Michael Desselle, AEP (Co-Chair)  
Mary Ellen Paravalos, National Grid  
Syd Berwager, BPA  
John Anderson, ELCON  
Lou Oberski, Dominion  
Barry Green, Ontario Power Generation  
Alan Johnson, Mirant

##### **IRC Members/Alternates**

Karl Tammar, NYISO  
Ed Riley, CAISO (for J. Detmers)  
Bill Limbrick, IMO  
Bruce Balmat, PJM (for Audrey Zibelman)  
Carl Monroe, SPP

##### **Observers/Guests/Staff**

James Cargas, NAESB  
Ed Davis, Entergy  
Rae McQuade, NAESB  
Marjorie Pearlman, Energy East  
Jim Templeton, Consultant

The Secretary determined that a quorum of the JIC was present.

#### **Agenda**

Co-Chair Desselle reviewed the agenda and the agenda was adopted by consent without revision.

#### **NERC Version 0 Standards Initiative**

Gerry Cauley reviewed the goals and progress of the NERC initiative to translate its existing operating policies, planning standards, and compliance templates to reliability standards by February 2005. Key elements of the translation are a) adopting the functional model designations for entities responsible for complying with the standards and b) identifying business practices which should be transferred to NAESB. The NERC drafting team has sought inputs from the NERC technical committees and has worked closely with representatives of the NAESB Business Practice Standards Subcommittee to evaluate potential business practices. That evaluation is ongoing.

## **NAESB Version 0 Standards Initiative**

Rae McQuade reviewed the NAESB Version 0 business practice standards initiative and noted areas of the NERC operating policies that the NAESB Business Practice Standards Subcommittee has identified as potential business practice standards. In areas where the requirements appear to be both reliability and business practices, NAESB is considering the development of “shadow” business practices that are identical to the NERC Version 0 reliability standard. This would enable both organizations to share a common starting point for the development of Version 1 standards.

## **JIC Framework for Considering Version 0 Standards Proposals at July 16 Meeting**

The JIC discussed the framework for considering the NERC and NAESB Version 0 initiatives at the July 16 meeting in Tampa. It was agreed that the meeting should be structured as follows:

1. Consider general recommendations to proceed with the NERC and NAESB Version 0 standards requests as proposed.
2. Consider specific proposals for which there is agreement among the NAESB and NERC teams that portions of the NERC operating policies should become business practice standards.
3. Consider specific proposals for which there is not agreement among the NAESB and NERC teams that portions of the NERC operating policies should become business practice standards.

## **Adjourn**

There being no further business, the meeting was adjourned.



When completed, email to: [gerry.cauley@nerc.net](mailto:gerry.cauley@nerc.net)

## Standard Authorization Request Form

Title of Proposed Standard	Version 0 Reliability Standards
Request Date	4/16/04

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name Standards Transition Management Team	<input checked="" type="checkbox"/>	New Standard
Primary Contact Gerry Cauley	<input type="checkbox"/>	Revision to existing Standard
Telephone 609-452-8060 Fax 609-452-9550	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail gerry.cauley@nerc.net	<input type="checkbox"/>	Urgent Action

### Purpose/Industry Need (Provide one or two sentences)

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable - now.
2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

## Reliability Functions

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

The applicable functions will be identified in translation of existing operating policies, planning standards, and compliance templates into Version 0 standards. Although, all functions are checked above, some functions may not have performance requirements in the existing reliability rules.

## Reliability and Market Interface Principles

<b>Applicable Reliability Principles</b> <i>(Check boxes for all that apply by double clicking the grey boxes.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input checked="" type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input checked="" type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
<b>Does the proposed Standard comply with all of the following Market Interface Principles?</b> <i>(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)</i>	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

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

1. Translate the existing reliability rules - namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 - into an initial baseline (Version 0) set of reliability standards.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards.
3. Identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.
4. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.

A more detailed implementation plan is provided in the attached "Plan for Accelerating the Adoption of NERC Reliability Standards".

### ***Related Standards***

Standard No.	Explanation
1200	Urgent Action Cyber Security Standard is unaffected by this project, since it is already an approved standard.
	All other standards and SARS in development will continue as planned, except the implementation plan must be revised to consider what portions of Version 0 standards must be retired upon adoption of a Version 1 standard.

### ***Related SARs***

SAR ID	Explanation
	Same as above.

***Regional Differences***

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

***Related NERC Operating Policies or Planning Standards***

ID	Explanation
	The development of Version 0 standards is intended to retire all existing operating policies, planning standards, and compliance templates.

# **Plan for Accelerating the Adoption of NERC Reliability Standards**

**FINAL  
April 19, 2004**

**Standards Transition Management Team**

**Standards Authorization Committee**

## Standards Transition Overview

This document describes a plan for accelerating the transition from existing NERC operating policies, planning standards and compliance templates to an integrated set of reliability standards by February 2005. The goal is to develop a “Version 0” baseline set of standards translated from the existing requirements and measures provided in:

- The April 2, 2004 Board-approved compliance templates.
- The existing operating policies, including modifications to Operating Policies 5, 6, and 9 made to address lessons learned from the August 14, 2003, blackout.
- The existing planning standards.

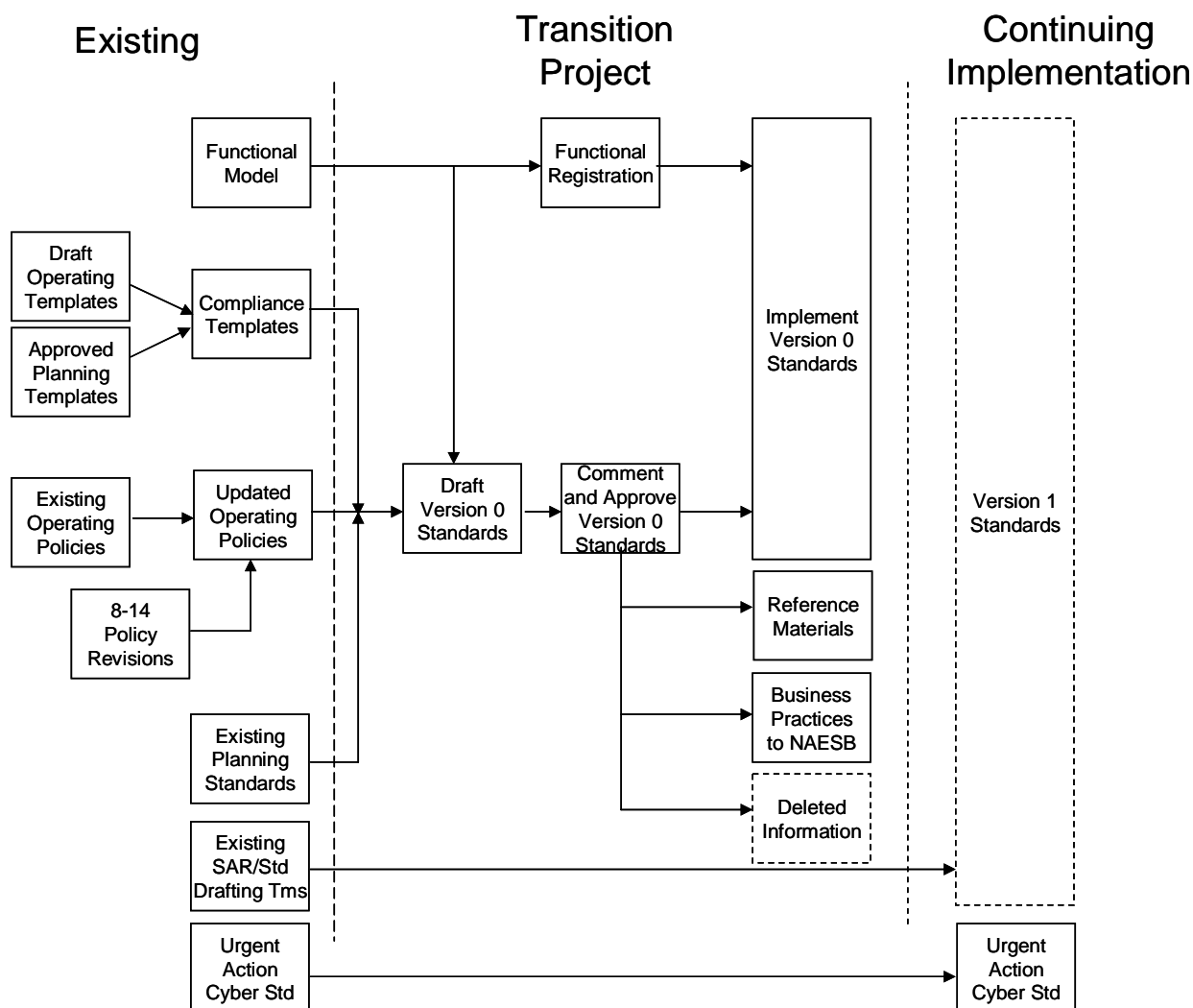


Figure 1 – Standards Transition Overview

In the drafting of the Version 0 standards, the Functional Model will be applied to designate functions to which each existing requirement and measure applies. In parallel, NERC and the

Regional Councils will seek to register all entities that perform the functions identified in the Version 0 standards.

The goal is to develop the Version 0 standards using the existing NERC Standards Process Manual. In the translation, portions of the existing reliability documents may be designated as Version 0 standards, potential business practice standards, reference materials, or may be subject to deletion.

Previously defined Standards Authorization Requests (SARs) and draft standards are expected to continue on their paths to adoption as Version 1 reliability standards, adding to or replacing the appropriate Version 0 standards subsequent to adoption of the Version 0 standards. The Urgent Action Cyber Security Standard (1200) is already a standard and is unaffected by the transition project.

A list of acronyms used in this plan is provided below for ease of reference.

ANSI	American National Standards Institute
BPRT	Business Practice Review Team
CCC	Compliance and Certification Committee
CCMC	Compliance and Certification Managers Committee
CIPC	Critical Infrastructure Protection Committee
DT	Drafting team
FERC	Federal Energy Regulatory Commission (FERC)
IRC	ISO/RTO Council
JIC	Joint Interface Committee
MC	Market Committee
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
OC	Operating Committee
PC	Planning Committee
SAC	Standards Authorization Committee
SAR	Standard Authorization Request
SPM	Standards Process Manual
STMT	Standards Transition Management Team
ST	Support Team



## Background

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. On this basis, ANSI certified NERC as an ANSI standards developer in March 2003. NERC adopted the ANSI-based standards procedure primarily in response to a transformation of the industry that saw the reliability responsibilities of a finite set of vertically integrated utilities become unbundled to a more diverse spectrum of entities forming the market-based wholesale electric industry. The open standards process allows all parties responsible for, or impacted by, bulk electric system reliability to participate in the standards process.

The development of new reliability standards was initially conceived to start from a “clean slate”, rather than translating existing NERC operating policies and planning standards. A clean slate approach was preferred because it allowed better organization of the standards and necessitated establishing a logical reliability basis for proposing a standard rather than assuming continuation of ‘the way it has always been done’. There are currently 16 reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security adopted in August 2003 as an urgent action. Despite the progress to date, the development of reliability standards in the new process has been slower than initially expected.

Pending adoption of a minimum set of reliability standards, the NERC Operating Committee (OC) has continued to maintain its nine operating policies and associated appendices through the use of a transitional procedure. NERC also has 48 planning standards and 91 associated measures that were developed by the Planning Committee (PC). The concept until now for transitioning from existing operating policies and planning standards to new standards has been to adopt each new standard individually and retire appropriate sections of the existing documents, although a detailed plan was never developed and no standards have been transitioned in this manner.

The Functional Model was adopted by the NERC board initially in June 2001 and was revised in February 2004. The Functional Model provides a flexible framework for developing reliability standards in an unbundled industry in which the control area operated by a vertically integrated utility is no longer the sole entity responsible for reliability. Although the Functional Model has gained widespread acceptance conceptually, it has not yet seen significant application by NERC or the industry.

## Need for Accelerating the Standards Transition

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: “NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.”
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing “the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable.”
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC’s reliability policy objective, as noted above.

As an immediate step, the NERC board on April 2, 2004 adopted a set of 38 compliance templates to augment the existing operating policies and planning standards by clarifying some requirements and adding measures to be used in compliance audits. While not covering the complete set of operating policies and planning standards, the compliance templates address the most significant reliability issues to be reviewed during compliance evaluations. Additionally, the OC has proposed revisions to Operating Policies 5, 6 and 9 to clarify the responsibilities and authorities of control areas and reliability coordinators.

With the adoption of the compliance templates in April 2004, NERC now has four different sets of reliability documents: operating policies, planning standards, compliance templates, and emerging new reliability standards. Maintaining these documents creates an unnecessary burden on the industry of working in multiple forums and is an inefficient dilution of resources. In most cases, there has been a concerted effort to maintain a separation between standard drafting teams in the new process and the technical committees, resulting in multiple groups working on related topics. These demands are in addition to the need for the industry to participate in the development of business practice standards by the North American Energy Standards Board (NAESB).

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities who must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step.

### **Objectives of the Accelerated Standards Transition**

The goal of the accelerated standards transition project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates,

into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process.

Specific objectives are to:

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards for adoption by the NERC Board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC) identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent “Version 0” business practice standards.
5. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.
6. Coordinate Version 0 standards development with the Compliance and Certification Committee (CCC) and Compliance and Certification Managers Committee (CCMC), to assist them in developing the compliance monitoring program for 2005 and beyond.
7. Support the continuing development of Version 1 reliability standards already in progress to become additions to or replacements of applicable sections of Version 0. Any new standards would be implemented subsequent to the adoption of Version 0.
8. Be prepared beginning in 2005 to consolidate the use of technical resources working in similar content areas (e.g. technical committees and drafting teams) to make more efficient use of resources in developing and revising standards.
9. Evaluate and improve the standards process so that it is responsive to reliability needs, while complying with the ANSI essential requirements.

## **Guiding Principles**

The following principles are essential to the success of this project:

1. To expedite consensus, the scope of the Version 0 standards will incorporate the existing reliability rules in effect in April 2004 – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the Board on April 2, and approved revisions to Operating Policies 5, 6, and 9 that are being balloted in April 2004. The Standards Authorization Committee (SAC) and the Standards Transition Management Team (STMT) strongly urge that previous transitional processes not be used to

further modify the existing operating policies, planning standards, and compliance templates during the translation to Version 0 standards.

2. In the drafting of Version 0 standards, when differences are identified in the language used in an existing operating policy or planning standard compared to that of a corresponding Board-approved compliance template, the more explicit statements of requirements and measures, generally contained in the compliance templates, will be adopted. For existing operating policy requirements that have no corresponding compliance template, the measures will be shown as “Not Specified”, rather than proposing new measures. Board-approved compliance templates for which there is no corresponding operating policy requirement or planning standard shall nonetheless be included as part of the Version 0 standards.
3. NERC will utilize the existing ANSI-accredited standards process for the development and adoption of the Version 0 standards. To expedite the transition, the Standards Authorization Committee (SAC) will manage some steps in parallel and manage the number of comment periods.
4. The Version 0 standards will be developed with due consideration of the impacts on existing NERC and Regional Council compliance monitoring programs.
5. NERC will work closely with NAESB, the IRC, the Regional Councils and the industry to achieve the stated objectives.
6. To facilitate consensus, a detailed mapping will be provided to show how the existing reliability documents translate into Version 0 standards, reference documents, and business practices. Therefore, each interim draft will retain information on the changes made, such as designation of new functions or identification of reference material or business practices.
7. A successful project depends on building consensus. Several checkpoints have been included in the project timeline to assess consensus.
8. All stakeholders are strongly encouraged to provide inputs early in the transition, especially during the public comment periods for the SAR and draft Version 0 standards. Because of the complexity of the project, no additional revisions will be permitted once the Version 0 standards are posted for committee and ballot pool approval.

## **Project Management**

The NERC Director of Standards will serve as project director.

The STMT, comprised of the Vice Chairperson of each of the NERC committees, serves as the project requestor by sponsoring the SAR for the Version 0 standards and has associated decision authorities as outlined in the detailed schedule below. The STMT also ensures that the standards transition activities of the various committees are coordinated. Each committee retains its existing authorities and responsibilities as related to this project.

The SAC manages the ANSI-accredited standards development process for the development and approval of the Version 0 standards. Specific responsibilities are outlined in the detailed project schedule. Additionally, the SAC retains all of its responsibilities and authorities identified in the Standards Process Manual. The STMT and SAC must work closely together, with the SAC managing the standards process and the STMT coordinating work efforts and actions among the various committees.

In accordance with the Standards Process Manual, the SAC will appoint a Version 0 drafting team with due consideration of expertise and balance. To expedite the work effort, it is expected the drafting team may form subgroups, such as operating and planning, to work on portions of the Version 0 standards. A small support team, comprised of several staff members and consultants, will be assigned to assist the drafting team in developing their work.

### **Major Milestone Deliverables**

The major milestone deliverables are as follows:

<b>Date</b>	<b>Milestone</b>
4/19/04	Transition plan approved for publication.
4/19/04	SAR on Version 0 standards posted for comment until May 17.
4/19/04	Solicit nominations for Version 0 drafting team and self-selection for ballot pool.
5/7/04	Version 0 drafting team formed.
5/28/04	Consideration of comments on the SAR posted. Evaluation of consensus based on comments received and support for project.
6/4/04	Inputs to Version 0 standards received from technical subcommittees.
7/2/04	First draft of Version 0 standards posted for standing committee agendas and public comment.
8/30/04	Second draft Version 0 standards posted for public comment until October 15, 2004
10/15/04	Initial registration of applicable reliability functions completed.
10/25/04	Third draft Version 0 standards posted to standing committees for endorsement at November 8-12 meetings.
10/25/04	Third draft Version 0 standards posted to ballot pool for 30-day pre-ballot period.
11/12/04	Standing committees endorse Version 0 standards.
12/10/04	Initial ballot of Version 0 standards complete.
1/7/05	Second ballot of Version 0 standards complete (assuming a recirculation ballot is required).
1/10/05	Final draft Version 0 standards posted for Board adoption.
2/8/05	Board adoption of Version 0 standards.

## Implementation Schedule

The schedule below provides a work plan to achieve the stated objectives. The dates shown are expected completion dates – many tasks must begin well before the specified dates.

<b>Date</b>	<b>Task</b>	<b>Assigned To</b>
4/14/04	Approve SAR for Version 0 standards and appoint STMT as SAR drafting team for the purpose of considering comments.	SAC
4/14/04	Approve Version 0 standard drafting team nomination form.	SAC
4/19/04	Approve transition plan.	STMT/SAC
4/19/04	Post and announce: <ul style="list-style-type: none"> <li>• Transition plan.</li> <li>• SAR (through 5/17/04).</li> <li>• Request for nominations to Version 0 standard drafting team (through 4/30/04).</li> <li>• Self-selection for Version 0 ballot pool.</li> </ul>	NERC Staff
4/19/04	Assign technical subcommittees to provide inputs to Version 0 standards, as appropriate.	OC/PC/MC
4/19/04	Assign 3-4 person dedicated Support Team (ST), comprised of staff and contractors, to begin initial work and assist drafting team.	NERC Staff
4/19/04	Inform MC and NAESB of need to form a business practice review team (BPRT) to coordinate assimilation of business practices.	NERC Staff
4/19/04	Inform Organization Certification Working Group and Regional Councils of objectives and timeline for initial functional registration by October 15, 2004.	NERC Staff
4/19/04	Inform CCC and CCMC of objectives and timeline for evaluating impacts on the 2005 compliance program and preparing the 2005 compliance plan.	NERC Staff
4/21-22/04	OC subcommittees meet and work on inputs to Version 0	OC
4/30/04	Close nominations for Version 0 standard drafting team.	NERC Staff
4/30/04	Approve posting of Standards Process Manual (SPM) revision to allow SAC to make administrative and procedural revisions to the manual.	SAC
5/7/04	Approve Version 0 standard drafting team.	SAC
5/14/04	Initial mapping of compliance templates into Version 0 format. Significant progress in mapping planning standards into Version 0 format.	ST

## Standards Transition Plan (Final)

April 19, 2004

5/17/04	Close Version 0 SAR comment period.	NERC Staff
5/17/04	Post revision to SPM for comment through June 17.	SPM DT
5/18/04	Review SAR and project plans with JIC for informational purposes.	SAC/JIC
5/20-21/04	Initial meeting of Version 0 drafting team (DT).	DT/ST
5/28/04	Prepare and post consideration of comments on SAR. Evaluate and report to SAC on consensus.	STMT
5/28/04	Finalize Version 0 communications plan.	SAC
5/28/04	Assess consensus based on SAR comments and approve drafting of Version 0 standards.	SAC
6/4/04	Provide inputs to draft Version 0 standards.	OC/PC/MC
6/4/04	Forward OC/PC/MC subcommittee recommendations on business practices to BPRT.	NERC Staff
6/9-11/04	Version 0 drafting team second meeting.	DT/ST
6/9/04	Version 0 drafting team finalizes general organization and numbering scheme for Version 0 standards.	DT/ST
6/15/04	Approve transition project.	Board
6/28-30	Drafting team third meeting to finalize draft 1 of Version 0 standards.	DT/ST
7/2/04	Post first draft of Version 0 standards for standing committee agendas and public comment. Key unresolved issues highlighted.	NERC Staff
7/20-26	Standing committee review of first draft Version 0.	OC/PC/MC/CIPC
7/30/04	Close comment period on first draft of Version 0 standard.	NERC Staff
8/9-10/04	SAC meeting.	SAC
8/11-13/04	Drafting team meeting to prepare second draft and response to comments.	DT/ST
8/30/04	Post second draft Version 0 standards for public comment until 10/15/04.	DT/ST
8/30/04	Complete ballot of revision to SPM to allow SAC revisions to administrative procedures.	SPM DT
10/4/04	Proposed revisions to streamline SPM steps posted for 30-day comment period.	
10/15/04	Complete initial registration of applicable reliability functions.	OCTF/Reliability Councils
10/15/04	Close comment period on draft 2.	NERC Staff
10/22/04	Prepare consideration of comments on draft 2 and prepare draft 3 of Version 0 for posting to standing committees for	DT/ST

	endorsement at November 9-11 meetings.	
10/25/04	Evaluate consensus and determine whether to ballot Version 0 standards.	SAC
10/25/04	Post draft 3 Version 0 standards to ballot pool for 30-day pre-ballot period.	NERC Staff
11/8-12/04	Standing committees endorse Version 0 standards by committee action.	OC/PC/MC/CIPC
11/11-12/04	SAC meeting. Assess consensus on Version 0 going to ballot and proposed revisions to streamline the Standards Process Manual.	SAC
12/10/04	Complete first ballot of Version 0 standards.	Ballot Pool
12/15/04	Complete consideration of comments submitted with negative ballots, if needed.	SPM/Drafting Team
1/7/05	Complete recirculation ballot of Version 0 standards, if needed.	Ballot Pool
1/10/05	Post final draft Version 0 standards for Board adoption February 8, 2005	NERC Staff
1/12/05	SCEC and SAC executives joint meeting to coordinate use of technical resources in development of standards.	SCEC/SAC
2/8/05	Board considers adoption of Version 0 standards.	BOT



**Plan for Accelerating the  
Adoption of NERC Reliability Standards  
FINAL**

**Approved by NERC Board of Trustees  
June 15, 2004**

## Standards Transition Overview

This document describes a plan for accelerating the transition from existing NERC operating policies, planning standards and compliance templates to an integrated set of reliability standards by February 2005. The goal is to develop a “Version 0” baseline set of standards translated from the existing requirements and measures provided in:

- The April 2, 2004 Board-approved compliance templates.
- The existing operating policies, including modifications to Operating Policies 5, 6, and 9 made to address lessons learned from the August 14, 2003, blackout.
- The existing planning standards.

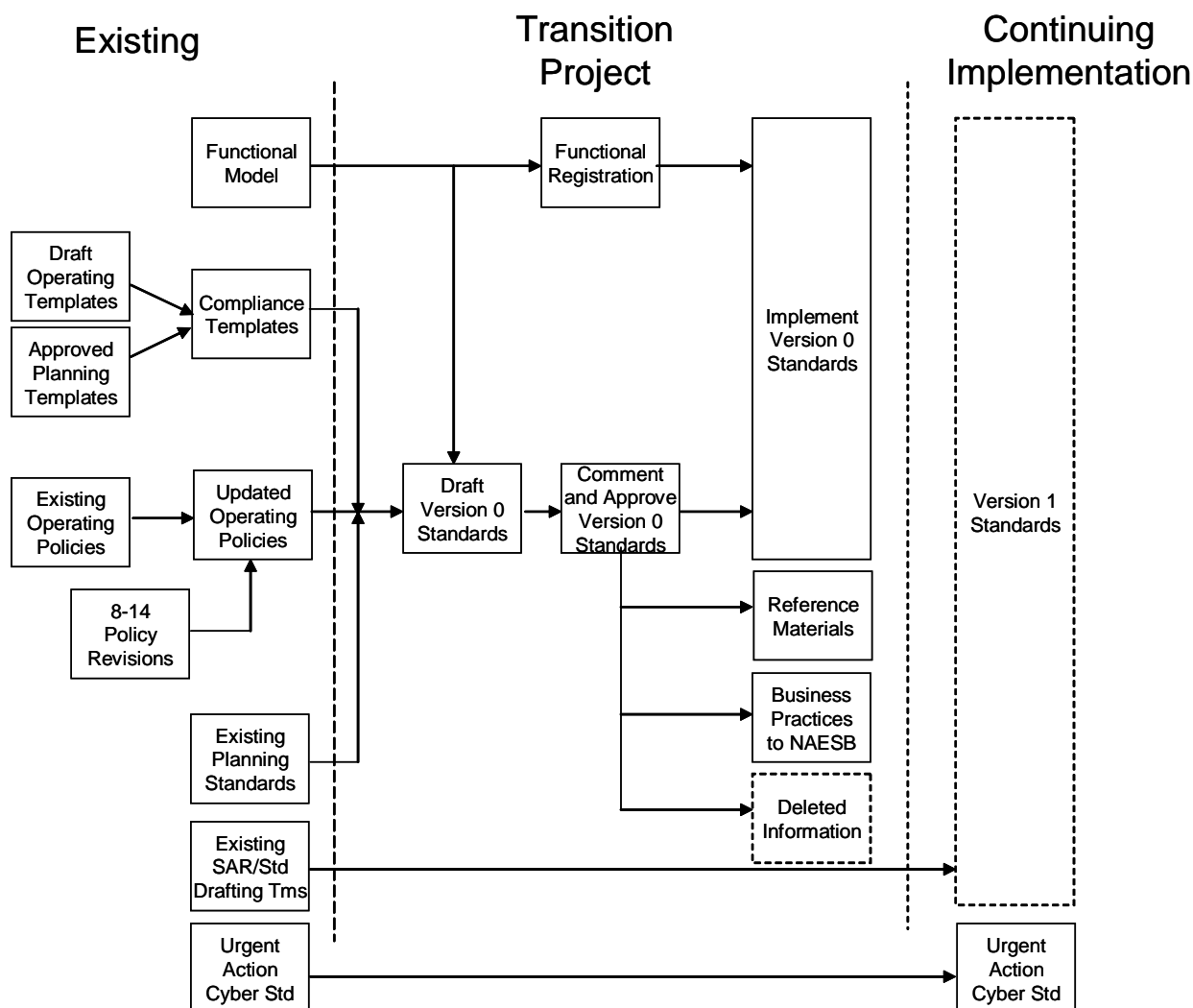


Figure 1 – Standards Transition Overview

In the drafting of the Version 0 standards, the Functional Model will be applied to designate functions to which each existing requirement and measure applies. In parallel, NERC and the

Regional Councils will seek to register all entities that perform the functions identified in the Version 0 standards.

The goal is to develop the Version 0 standards using the existing NERC Standards Process Manual. In the translation, portions of the existing reliability documents may be designated as Version 0 standards, potential business practice standards, reference materials, or may be subject to deletion.

Previously defined Standards Authorization Requests (SARs) and draft standards are expected to continue on their paths to adoption as Version 1 reliability standards, adding to or replacing the appropriate Version 0 standards subsequent to adoption of the Version 0 standards. The Urgent Action Cyber Security Standard (1200) is already a standard and is unaffected by the transition project.

A list of acronyms used in this plan is provided below for ease of reference.

ANSI	American National Standards Institute
BPRT	Business Practice Review Team
CCC	Compliance and Certification Committee
CCMC	Compliance and Certification Managers Committee
CIPC	Critical Infrastructure Protection Committee
DT	Drafting team
FERC	Federal Energy Regulatory Commission (FERC)
IRC	ISO/RTO Council
JIC	Joint Interface Committee
MC	Market Committee
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
OC	Operating Committee
PC	Planning Committee
SAC	Standards Authorization Committee
SAR	Standard Authorization Request
SPM	Standards Process Manual
STMT	Standards Transition Management Team
ST	Support Team

## Background

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. On this basis, ANSI certified NERC as an ANSI standards developer in March 2003. NERC adopted the ANSI-based standards procedure primarily in response to a transformation of the industry that saw the reliability responsibilities of a finite set of vertically integrated utilities become unbundled to a more diverse spectrum of entities forming the market-based wholesale electric industry. The open standards process allows all parties responsible for, or impacted by, bulk electric system reliability to participate in the standards process.

The development of new reliability standards was initially conceived to start from a “clean slate”, rather than translating existing NERC operating policies and planning standards. A clean slate approach was preferred because it allowed better organization of the standards and necessitated establishing a logical reliability basis for proposing a standard rather than assuming continuation of ‘the way it has always been done’. There are currently 16 reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security adopted in August 2003 as an urgent action. Despite the progress to date, the development of reliability standards in the new process has been slower than initially expected.

Pending adoption of a minimum set of reliability standards, the NERC Operating Committee (OC) has continued to maintain its nine operating policies and associated appendices through the use of a transitional procedure. NERC also has 48 planning standards and 91 associated measures that were developed by the Planning Committee (PC). The concept until now for transitioning from existing operating policies and planning standards to new standards has been to adopt each new standard individually and retire appropriate sections of the existing documents, although a detailed plan was never developed and no standards have been transitioned in this manner.

The Functional Model was adopted by the NERC board initially in June 2001 and was revised in February 2004. The Functional Model provides a flexible framework for developing reliability standards in an unbundled industry in which the control area operated by a vertically integrated utility is no longer the sole entity responsible for reliability. Although the Functional Model has gained widespread acceptance conceptually, it has not yet seen significant application by NERC or the industry.

## Need for Accelerating the Standards Transition

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: “NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.”
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing “the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable.”
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC’s reliability policy objective, as noted above.

As an immediate step, the NERC board on April 2, 2004 adopted a set of 38 compliance templates to augment the existing operating policies and planning standards by clarifying some requirements and adding measures to be used in compliance audits. While not covering the complete set of operating policies and planning standards, the compliance templates address the most significant reliability issues to be reviewed during compliance evaluations. Additionally, the OC has proposed revisions to Operating Policies 5, 6 and 9 to clarify the responsibilities and authorities of control areas and reliability coordinators.

With the adoption of the compliance templates in April 2004, NERC now has four different sets of reliability documents: operating policies, planning standards, compliance templates, and emerging new reliability standards. Maintaining these documents creates an unnecessary burden on the industry of working in multiple forums and is an inefficient dilution of resources. In most cases, there has been a concerted effort to maintain a separation between standard drafting teams in the new process and the technical committees, resulting in multiple groups working on related topics. These demands are in addition to the need for the industry to participate in the development of business practice standards by the North American Energy Standards Board (NAESB).

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities who must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step.

### **Objectives of the Accelerated Standards Transition**

The goal of the accelerated standards transition project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates,

into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process.

Specific objectives are to:

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards for adoption by the NERC Board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC) identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent “Version 0” business practice standards.
5. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.
6. Coordinate Version 0 standards development with the Compliance and Certification Committee (CCC) and Compliance and Certification Managers Committee (CCMC), to assist them in developing the compliance monitoring program for 2005 and beyond.
7. Support the continuing development of Version 1 reliability standards already in progress to become additions to or replacements of applicable sections of Version 0. Any new standards would be implemented subsequent to the adoption of Version 0.
8. Be prepared beginning in 2005 to consolidate the use of technical resources working in similar content areas (e.g. technical committees and drafting teams) to make more efficient use of resources in developing and revising standards.
9. Evaluate and improve the standards process so that it is responsive to reliability needs, while complying with the ANSI essential requirements.

## **Guiding Principles**

The following principles are essential to the success of this project:

1. To expedite consensus, the scope of the Version 0 standards will incorporate the existing reliability rules in effect in April 2004 – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the Board on April 2, and approved revisions to Operating Policies 5, 6, and 9 that are being balloted in April 2004. The Standards Authorization Committee (SAC) and the Standards Transition Management Team (STMT) strongly urge that previous transitional processes not be used to

further modify the existing operating policies, planning standards, and compliance templates during the translation to Version 0 standards.

2. In the drafting of Version 0 standards, when differences are identified in the language used in an existing operating policy or planning standard compared to that of a corresponding Board-approved compliance template, the more explicit statements of requirements and measures, generally contained in the compliance templates, will be adopted. For existing operating policy requirements that have no corresponding compliance template, the measures will be shown as “Not Specified”, rather than proposing new measures. Board-approved compliance templates for which there is no corresponding operating policy requirement or planning standard shall nonetheless be included as part of the Version 0 standards.
3. NERC will utilize the existing ANSI-accredited standards process for the development and adoption of the Version 0 standards. To expedite the transition, the Standards Authorization Committee (SAC) will manage some steps in parallel and manage the number of comment periods.
4. The Version 0 standards will be developed with due consideration of the impacts on existing NERC and Regional Council compliance monitoring programs.
5. NERC will work closely with NAESB, the IRC, the Regional Councils and the industry to achieve the stated objectives.
6. To facilitate consensus, a detailed mapping will be provided to show how the existing reliability documents translate into Version 0 standards, reference documents, and business practices. Therefore, each interim draft will retain information on the changes made, such as designation of new functions or identification of reference material or business practices.
7. A successful project depends on building consensus. Several checkpoints have been included in the project timeline to assess consensus.
8. All stakeholders are strongly encouraged to provide inputs early in the transition, especially during the public comment periods for the SAR and draft Version 0 standards. Because of the complexity of the project, no additional revisions will be permitted once the Version 0 standards are posted for committee and ballot pool approval.

## **Project Management**

The NERC Director of Standards will serve as project director.

The STMT, comprised of the Vice Chairperson of each of the NERC committees, serves as the project requestor by sponsoring the SAR for the Version 0 standards and has associated decision authorities as outlined in the detailed schedule below. The STMT also ensures that the standards transition activities of the various committees are coordinated. Each committee retains its existing authorities and responsibilities as related to this project.

The SAC manages the ANSI-accredited standards development process for the development and approval of the Version 0 standards. Specific responsibilities are outlined in the detailed project schedule. Additionally, the SAC retains all of its responsibilities and authorities identified in the Standards Process Manual. The STMT and SAC must work closely together, with the SAC managing the standards process and the STMT coordinating work efforts and actions among the various committees.

In accordance with the Standards Process Manual, the SAC will appoint a Version 0 drafting team with due consideration of expertise and balance. To expedite the work effort, it is expected the drafting team may form subgroups, such as operating and planning, to work on portions of the Version 0 standards. A small support team, comprised of several staff members and consultants, will be assigned to assist the drafting team in developing their work.

### **Major Milestone Deliverables**

The major milestone deliverables are as follows:

<b>Date</b>	<b>Milestone</b>
4/19/04	Transition plan approved for publication.
4/19/04	SAR on Version 0 standards posted for comment until May 17.
4/19/04	Solicit nominations for Version 0 drafting team and self-selection for ballot pool.
5/7/04	Version 0 drafting team formed.
5/28/04	Consideration of comments on the SAR posted. Evaluation of consensus based on comments received and support for project.
6/4/04	Inputs to Version 0 standards received from technical subcommittees.
7/2/04	First draft of Version 0 standards posted for standing committee agendas and public comment.
8/30/04	Second draft Version 0 standards posted for public comment until October 15, 2004
10/15/04	Initial registration of applicable reliability functions completed.
10/25/04	Third draft Version 0 standards posted to standing committees for endorsement at November 8-12 meetings.
10/25/04	Third draft Version 0 standards posted to ballot pool for 30-day pre-ballot period.
11/12/04	Standing committees endorse Version 0 standards.
12/10/04	Initial ballot of Version 0 standards complete.
1/7/05	Second ballot of Version 0 standards complete (assuming a recirculation ballot is required).
1/10/05	Final draft Version 0 standards posted for Board adoption.
2/8/05	Board adoption of Version 0 standards.



## Implementation Schedule

The schedule below provides a work plan to achieve the stated objectives. The dates shown are expected completion dates – many tasks must begin well before the specified dates.

<b>Date</b>	<b>Task</b>	<b>Assigned To</b>
4/14/04	Approve SAR for Version 0 standards and appoint STMT as SAR drafting team for the purpose of considering comments.	SAC
4/14/04	Approve Version 0 standard drafting team nomination form.	SAC
4/19/04	Approve transition plan.	STMT/SAC
4/19/04	Post and announce: <ul style="list-style-type: none"> <li>• Transition plan.</li> <li>• SAR (through 5/17/04).</li> <li>• Request for nominations to Version 0 standard drafting team (through 4/30/04).</li> <li>• Self-selection for Version 0 ballot pool.</li> </ul>	NERC Staff
4/19/04	Assign technical subcommittees to provide inputs to Version 0 standards, as appropriate.	OC/PC/MC
4/19/04	Assign 3-4 person dedicated Support Team (ST), comprised of staff and contractors, to begin initial work and assist drafting team.	NERC Staff
4/19/04	Inform MC and NAESB of need to form a business practice review team (BPRT) to coordinate assimilation of business practices.	NERC Staff
4/19/04	Inform Organization Certification Working Group and Regional Councils of objectives and timeline for initial functional registration by October 15, 2004.	NERC Staff
4/19/04	Inform CCC and CCMC of objectives and timeline for evaluating impacts on the 2005 compliance program and preparing the 2005 compliance plan.	NERC Staff
4/21-22/04	OC subcommittees meet and work on inputs to Version 0	OC
4/30/04	Close nominations for Version 0 standard drafting team.	NERC Staff
4/30/04	Approve posting of Standards Process Manual (SPM) revision to allow SAC to make administrative and procedural revisions to the manual.	SAC
5/7/04	Approve Version 0 standard drafting team.	SAC
5/14/04	Initial mapping of compliance templates into Version 0 format. Significant progress in mapping planning standards into Version 0 format.	ST

## Standards Transition Plan (Final)

June 15, 2004

5/17/04	Close Version 0 SAR comment period.	NERC Staff
5/17/04	Post revision to SPM for comment through June 17.	SPM DT
5/18/04	Review SAR and project plans with JIC for informational purposes.	SAC/JIC
5/20-21/04	Initial meeting of Version 0 drafting team (DT).	DT/ST
5/28/04	Prepare and post consideration of comments on SAR. Evaluate and report to SAC on consensus.	STMT
5/28/04	Finalize Version 0 communications plan.	SAC
5/28/04	Assess consensus based on SAR comments and approve drafting of Version 0 standards.	SAC
6/4/04	Provide inputs to draft Version 0 standards.	OC/PC/MC
6/4/04	Forward OC/PC/MC subcommittee recommendations on business practices to BPRT.	NERC Staff
6/9-11/04	Version 0 drafting team second meeting.	DT/ST
6/9/04	Version 0 drafting team finalizes general organization and numbering scheme for Version 0 standards.	DT/ST
6/15/04	Approve transition project.	Board
6/28-30	Drafting team third meeting to finalize draft 1 of Version 0 standards.	DT/ST
7/2/04	Post first draft of Version 0 standards for standing committee agendas and public comment. Key unresolved issues highlighted.	NERC Staff
7/20-26	Standing committee review of first draft Version 0.	OC/PC/MC/CIPC
7/30/04	Close comment period on first draft of Version 0 standard.	NERC Staff
8/9-10/04	SAC meeting.	SAC
8/11-13/04	Drafting team meeting to prepare second draft and response to comments.	DT/ST
8/30/04	Post second draft Version 0 standards for public comment until 10/15/04.	DT/ST
8/30/04	Complete ballot of revision to SPM to allow SAC revisions to administrative procedures.	SPM DT
10/4/04	Proposed revisions to streamline SPM steps posted for 30-day comment period.	
10/15/04	Complete initial registration of applicable reliability functions.	OCTF/Reliability Councils
10/15/04	Close comment period on draft 2.	NERC Staff
10/22/04	Prepare consideration of comments on draft 2 and prepare draft 3 of Version 0 for posting to standing committees for	DT/ST

	endorsement at November 9-11 meetings.	
10/25/04	Evaluate consensus and determine whether to ballot Version 0 standards.	SAC
10/25/04	Post draft 3 Version 0 standards to ballot pool for 30-day pre-ballot period.	NERC Staff
11/8-12/04	Standing committees endorse Version 0 standards by committee action.	OC/PC/MC/CIPC
11/11-12/04	SAC meeting. Assess consensus on Version 0 going to ballot and proposed revisions to streamline the Standards Process Manual.	SAC
12/10/04	Complete first ballot of Version 0 standards.	Ballot Pool
12/15/04	Complete consideration of comments submitted with negative ballots, if needed.	SPM/Drafting Team
1/7/05	Complete recirculation ballot of Version 0 standards, if needed.	Ballot Pool
1/10/05	Post final draft Version 0 standards for Board adoption February 8, 2005	NERC Staff
1/12/05	SCEC and SAC executives joint meeting to coordinate use of technical resources in development of standards.	SCEC/SAC
2/8/05	Board considers adoption of Version 0 standards.	BOT

## **Comment Form Part 1 — Background Information Draft 1 of Proposed Version 0 Reliability Standards**

### **References**

Draft 1 of the Version 0 Reliability Standards and supporting materials may be downloaded from the following web page:

<http://www.nerc.com/~filez/standards/Version-0.html>.

Note that operating and planning standards are posted as two separate files. Additional supporting materials are posted at the same location.

Working documents and related files used by the Version 0 Standards Drafting Team are available at:

<http://www.nerc.com/~filez/standards/Version-0-RF.html>.

The Drafting Team used the most recently approved source document — either the Compliance Templates approved by the NERC Board of Trustees on April 2, 2004; the latest approved version of an operating policy or appendix (including revisions to Operating Policies 5, 6, and 9 approved by the NERC Board on June 15); and the latest approved planning standards and associated compliance templates. All of the “source” documents used by the Drafting Team are available for download on the related files page indicated above.

### **Purpose of the Comment Form**

The purpose of this form is to solicit comments on Draft 1 of NERC’s proposed Version 0 Reliability Standards. The form is in two parts. This first part is a read-only document that provides background information. The second part is a separate questionnaire that allows the commenter to enter comments in data fields provided. Due to the large number of comments expected, it is important that each commenter use the separate questionnaire form provided to submit comments.

### **Drafting Team Scope**

The Version 0 Standards Drafting Team was assigned by the Standards Authorization Committee to translate the existing NERC Compliance Templates, Operating Policies and Planning Standards into a baseline set of reliability standards. The Drafting Team was given the following guidance in completing the translation:

- Identify the appropriate Functional Model designation for each requirement (i.e. incorporate the Functional Model into the standards).
- Identify business practices that would be suitable to transfer to NAESB for development of business practice standards.
- Change the obligations imposed by the existing Compliance Templates, Operating Policies, and Planning Standards as little as possible in the translation.

### **Drafting Team Work to Date**

The Drafting Team met three times in late May and June to develop the initial draft Version 0 Standards. Extensive work was also done by team members between meetings, and two consultants and two NERC staff assisted the team. The principal challenge was the shear volume of the documents involved in

translating all of the compliance templates, operating policies, and planning standards in six weeks. Early on, it was apparent that the group needed to work in planning and operating subgroups in order to meet the aggressive schedule.

The operating subgroup further divided into small teams, with each team converting one operating policy. Operating Committee subcommittee inputs were received and incorporated into the draft. These inputs were mainly in the form of markups of the operating policies to incorporate the Functional Model, identify business practices, and change the requirements to “active voice.” The Drafting Team refined these inputs and used them to develop Draft 1 of the Version 0 Standards.

The planning subgroup started with the planning standards and associated compliance templates. The translation was somewhat more direct than for the operating area, since the planning standards were already in a form similar to a reliability standard. One of the difficult challenges in the planning area was determining what planning standards and measures were in effect, given that they were in different stages of approval and field-testing.

### **Draft 1 Version 0 Products**

The Drafting Team has prepared the following documents:

- **Version 0 Reliability Standards** — Draft 1 contains 62 standards, 40 derived from the operating policies and 22 derived from the planning standards. The planning standards are further divided into sections, with a total of approximately 70 sections. Several hundred requirements are contained in the first draft of the Version 0 standards. It is important to note with this first posting that the draft standards are in a preliminary working-draft stage. The project plan called for getting a quick initial translation so that key issues could be identified and inputs sought from the industry early in the project.
- **Translation Mapping** — The planning standards have been translated using a template that compares the existing planning standards to the proposed new standards side-by-side on the same page. This direct comparison is intended to help the industry visualize the mapping from the old standards to the new ones. Due to the complexity of translating the operating policies and appendices, a similar comparison was not possible for the operating standards in the time frame allowed. Mapping of the translation in the operating area has been achieved by identifying the source for each Version 0 requirement (i.e. policy, section, and requirement number). As supporting material, marked up copies of the operating policies and appendices are being posted showing revisions made in the translation. The Drafting Team anticipates being able to complete the side-by-side mapping for a more direct comparison in the second posting.
- **Glossary of Terms Used in Reliability Standards** — The Drafting Team is developing a glossary of defined terms used in the standards. The intent is to embody this glossary as an integral part of the Version 0 standards. The team is adopting existing approved terms used in the operating policies and planning standards, and other approved references as needed.
- **Identified Business Practices** — The Drafting Team has identified potential business practices in the operating policies (none were identified in the planning standards) and has shared that information with NAESB representatives. Recommendations of the Drafting Team and the NAESB Business Practice Standards Subcommittee will be considered by the Joint Interface Committee on July 16.
- **Identified Reference Materials** — The Drafting Team is compiling a list of guides and other reference materials from the operating policies and planning standards that are not being included in the Version 0 standards because they are not requirements. The Drafting Team will request the

Operating and Planning Committees to adopt that material into any reference documents needed to support the Version 0 standards.

### Translation Summary — Operating Policies and Associated Compliance Templates

The translation of the operating policies and appendices and associated compliance templates began with a markup of the source documents to:

- Identify the appropriate function.
- Identify business practices.
- Identify reference materials.
- Revise the requirements to be stated in “active” voice.

This markup of the existing policies and appendices was done in close coordination with the sponsoring Operating Committee subcommittees. The marked up policies and appendices also identify where each requirement was captured in the draft Version 0 standards (e.g. standard and requirement number).

A template was created to for the operating standards:

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	Version 0 standard number.	Source policy, appendix, compliance template, or reference	
Title	Title of new standard.		
Purpose	Description of the purpose of the standard.		
Effective Date	Date proposed for Board adoption (February 8, 2005).		
Applicability	List of functions to whom the standard applies.		
Requirements	Numbered requirements. Each requirement is an active (shall) statement of required performance.		
Measures	Measures as provided in a compliance template if one existed. Only changes were to adopt the functional model.		
Regional Differences	Any existing approved waivers are identified.		
Compliance Monitoring Process	Description from the compliance template, once again with minimal changes except adopting the functional model language.		
Levels of Non Compliance	From the compliance template, once again with minimal changes except adopting the functional model language.		

The Drafting Team generally took a tack of developing one standard for each section of an operating policy. Exceptions were taken to achieve better organization of related standards. Some sections that were thin on requirements were merged with other related standards.

In the few cases where mandatory requirements or methods were defined in appendices, this information was extracted and brought forward into the standard. If the information was a concise statement of required performance, it became part of the requirement itself. If the information was too voluminous, such as a table, it was attached to the standard and made part of the standard by reference. In a couple of instances, such as methods for determining Area Control Error, the requirements were specified in an existing reference document. In these cases, the required material was moved into or attached to the standard.

The Drafting Team did not attempt to evaluate the merits of including guides in the standards. Since their status is voluntary today, the Drafting Team defaulted to assuming they would not be in Version 0 standards.

The translation of the operating materials was complicated by several factors:

- The policies often refer to Operating Authorities. Interpreting which functions apply to each requirement was a challenge and comments are being sought on the judgments made by the Drafting Team.
- The policies were developed by different subcommittees at different times. As a result, there was significant redundancy between requirements across the policies. The Drafting Team attempted to address some of the most obvious redundancies but erred on the side of not eliminating redundant requirements if it would be difficult for the industry to follow the changes. The drafting team would like to refine the draft standards in the next posting by further reducing redundancies and better grouping of the requirements, but defers to inputs from industry in the first posting.
- The Drafting Team determined that it was not possible to implement the Functional Model concepts for interchange. Adopting the Interchange Authority model would require substantial changes to the industry's current methods of scheduling interchange. There would not be sufficient time prior to February 2005 to change the software tools and procedures and complete training to implement the Interchange Authority function. The Drafting Team recommends that the current "control area" scheduling method be retained in the Version 0 standards and that the Balancing Authority be designated to perform the current control area balancing functions, including scheduling.
- Policy 9 and parts of other standards reference requirements of Reliability Coordinators. However, Reliability Coordinators are not defined as a function in the Functional Model. The Drafting Team considered several alternatives for treating Reliability Coordinator requirements. The Drafting Team recommends that a partial implementation of the Functional Model be completed in Version 0 by assigning all Reliability Coordinator requirements to the Reliability Authority Function. For organizations that perform both, the translation is straightforward. In some regions, the existing control areas intend to retain the Reliability Authority function. In those cases, the requirements in Version 0 assigned to the Reliability Authority would apply, but the reliability coordination tasks may be delegated to another organization, such as an existing Reliability Coordinator.

## **Translation Summary — Planning Standards and Associated Compliance Templates**

The Draft 1 Version 0 planning standards are presented in a table format with the proposed Version 0 standard language on the left and the existing standard or compliance template language on the right to facilitate comparison. The Drafting Team made as few changes as possible and that should be apparent in the side-by-side comparison. Because of the amount of information in the table, this document is designed to be printed on **LEGAL** size paper.

The Drafting Team made the following global changes in the conversion of the planning standards and compliance templates:

- Converted the generic terms used to reference responsibility to the functions identified in the Functional Model wherever possible. Note that many planning standards include requirements for the Regional Reliability Councils and NERC, and these have been preserved in this conversion — the term Region was converted to Regional Reliability Council throughout Version 0.
- Converted “passive language” to “active” language to reduce ambiguity.
- Converted the “Measure” statements into “Requirements”. The Drafting Team agreed that the measures in the existing planning standards were the clearest sources for the “shall” statements defining performance obligations.
- In many cases, the standards included the same language that was repeated in the measures. To eliminate duplication in the conversion, the Drafting Team eliminated as much of this duplication as possible. Many of the “standard” (e.g. S1, S2) statements were very “global” and did not identify what function was to perform a task — these global, high-level standards statements were absorbed into the “purpose” statements.
- The Drafting Team added “comments” in the last column of each page to explain the changes made in the conversion from the original language in the “source” document to the proposed “draft” standard.

The Drafting Team cut and pasted existing language from the source documents, into the new Version 0 standards. The existing Compliance Templates don’t have the same headings as the new Reliability Standards, but both cover most of the same information. The following table shows how to interpret the Drafting Team’s conversion of “source” Compliance Templates into new Version 0 Standards.

<b>Draft Version 0 Standard Language</b>		<b>Source Document</b>		<b>Comments</b>
<b>Heading</b>	<b>New Language</b>	<b>Heading</b>	<b>Existing Document Language</b>	
Standard	(New standard’s number)	Compliance Templates	(Title of the Compliance Templates used as the source document for the proposed standard.)	
Title	(New title for entire standard.)	Section	(Sections of the Compliance Templates used as the source document.)	
Purpose	(Tells “why” the standard is needed — generally written as a summary of the source document’s “Standard” statements.)			
Effective Date	(Date of expected BOT adoption.)	Approval Dates	(Dates Compliance Templates were approved.)	
Standard Applicability	(Functions responsible for one or more of the requirements in the	Applicable to	(List of types of organizations or positions responsible	



	standard.)		for requirements in the Compliance Template.)	
Section # Standard	(Title of the Section – copied from Source Document’s Brief Description.) (Each of the Standards includes several Sections.)	Source ID# Brief Description	(Compliance Template’s Brief Description of this Measure.)	
Section # Applicability	(List of Functions responsible for the requirements of this Section of the new Standard — translated from source document into Functional Model terms.)	Source ID# Applicable to	(Type of organization or position responsible for this Measure.)	
Section # Requirements	(List of Requirements for this Section of the new Standard — translated from the source document’s “Measures”.)	Source ID# Standard & Measures	(List of Standard statements copied from the source document.)	
Section # Measure	(List of Measures for this Section of the new Standard — translated from the source document’s Items to be Measured.)	Source ID # Items to be Measured	(List of Items to be Measured, copied from the source document. In some cases, 100% Compliance was identified, and this also appears.)	Also used 100% Compliance Statements, Standard Statements & Levels of Non-compliance.)
Section # Regional Differences	(There were no regional differences in the source documents, so there are none in the Planning Version 0 standards.)		(There were no regional differences in the source documents, so there are none in the Planning Version 0 standards.)	
Section # Compliance Monitoring Process	(Copied the Timeframe and Compliance Monitoring Responsibility from the Source document.)	Source ID# Timeframe & Compliance Monitoring Responsibility	(Copied the Timeframe and Compliance Monitoring Responsibility from the Source document.)	
Section # Levels of Non-Compliance	(Copied from the Source document.)	Source ID# Levels of Non-Compliance	(Copied from the Source document.)	

A critical issue for the planning subgroup was what standards and measures to include in Version 0. Of particular concern are some measures which have not been field-tested and implemented by industry. The Drafting Team is recommending that measures that have not been field-tested or widely implemented by industry should not be included in the Version 0 standards, particularly if the measures appear to be onerous to implement. The Drafting Team is seeking industry input on this matter in certain standards.

Please use the following information as a reference when reviewing the conversion of planning standard compliance templates into Version 0 Reliability Standards. The existing planning standards were converted into compliance templates over several years, in different “phases”, with one phase field-tested at a time. The table below provides an overview of the four phases, and

Existing Planning Standards	Current Status
Phase 1	Approved by BOT and implemented — some were re-approved as part of the April 2, 2004 set of compliance templates.
Phase 2.A and Phase 2.B	Approved by BOT and implemented — some were re-approved as part of the April 2, 2004 set of compliance templates.
Phase 3	Field-tested, but results of field test not incorporated — note field test indicated some measures were acceptable/some needed changes — some were approved as part of the April 2, 2004 set of compliance templates (IIAM5, IIAM6, IIEM3, IIEM4, IVAM1, IVAM4.)
Phase 4	Not field testing conducted.

The following table shows the draft Version 0 Standard Numbers, and the associated source documents. (The sequence of Version 0 Standard Numbers doesn’t parallel the sequence of the existing Planning Standards — we will “fix” this in the next draft!)

Version 0 Standard	Planning Standard (Compliance Template)	Measure	Standard # for Measure	Phase for Field-Testing	Description of Measure
51	I. System Adequacy & Security. A. Transmission Systems	M1	S1	1	System performance under normal conditions
		M2	S2	1	System performance under single contingency
		M3	S3	2	System performance under multiple contingencies
		M4	S4	2	System performance under extreme contingencies
52	I. System Adequacy & Security. B. Reliability Assessment	M1	S1	1	Self-assessment of regional & interregional reliability
		M2	S1	1	Regional Data needed to assess reliability
53	I. System Adequacy & Security. C. Facilities Connection	M1	S1	1	Facilities connection requirements
		M2	S2	2	Coordinate plans for new facilities
54	I. System Adequacy & Security. E.1. TTC/ATC Transfer Capability	M1	S1	2B	Regional TTC/ATC Methodology
		M3	S1	2B	Regional Procedure - compliance with regional TTC/ATC method

		M4	S1	2B	Regional Procedure to collect & consider concerns
55	I. System Adequacy & Security. E.2. CBM/TRM Transfer Capability	M1	S1	2B	Regional CBM Methodology
		M3	S1	2B	Regional Procedure-compliance to regional CBM methodology
		M4	S1	2B	Document transmission provider procedures for use of CBM
56	I. System Adequacy & Security. E.2. CBM/TRM Transfer Capability	M5	S1	2B	Report use of CBM
		M6	S2	2B	Regional TRM Methodology
		M8	S2	2B	Regional Procedure-compliance to regional TRM methodology
57	I. System Adequacy & Security. F. Disturbance Monitoring	M1	S1	1	Document/define equipment Requirement
		M2	S1	3	List of monitoring equipment installations & operating status
		M3	S2	3	Disturbance monitoring data reporting Requirements
		M4	S2	3	Recorded fault and disturbance Data
		M5	S2	4	Use Database
58	II. System Modeling Data A. System Data	M1	S1	1	Steady state modeling DATA
		M2	S1	1	Reporting Requirements/Procedures for steady state modeling
		M3	S1	1	Dynamics modeling Data
		M4	S1	1	Reporting Requirements/Procedures for dynamics modeling
		M5	S1	3	Develop steady state models
		M6	S1	3	Develop dynamics models
59	II. System Modeling Data B. Generation Equipment	M1	S1	4	Procedures for validating generation equipment data
		M2	S1	4	Verification of gross & net dependable capability
		M3	S1	4	Verification of gross & reactive power capability of generators

		M4	S1	4	Test results of gen. voltage regulator controls & limit functions
		M5	S1	4	Test results of speed/load governor controls
		M6	S1	4	Verification of excitation system dynamic modeling data
60	II. System Modeling Data C. Facility Ratings	M1	S1	1	Methodology for determining facilities electrical ratings
		M2	S1	1	Facility electrical rating Data for modeling
61	II. System Modeling Data D. Actual & Forecast Demands	M1	S1	1	Demand, energy & DSM scope & specificity reporting Requirements
		M2	S1	4	Reporting procedures that ensure against double counting or omission of customer demand data
		M3	S1, S2	4	Procedures requiring consistency of data reported for reliability purposes and to gvt agencies
		M4	S1	1	Aggregated actual & forecast demand & energy Data
		M6	S1	2	Nonmember demand Data Document how uncertainty addressed
		M10	S2	1	Report interruptible demands & direct load control Data
		M11	S2	2	Inform operations of interruptible demands & direct load control
		M12	S2	2	Document/methodology of effects of controllable DSM
62	II. System Modeling Data E. Demand Characteristics (Dynamic)	M1	S1	4	Plans for the evaluation and reporting of voltage & frequency characteristics of customer demands

		M2	S1	4	Documentation of requirements for determining dynamic characteristics of customer demands
		M3	S1	4	Customer (dynamic) demand data
63	III. System Protection & Control. A. Transmission Protection Systems	M3	S3	2	Regional Process to monitor/notify/analyze trip operations — document misoperations
		M4	S4	2	Document/implement transmission protection system maintenance/testing/monitoring Program
		M5	S5	2	Provide trip operation/misoperation information per Regional process
64	I. System Adequacy & Security D. Voltage Support and Reactive Power	M1	S1	4	Assessment of reactive power resources
		M2	S1	4	Generator reactive power capability
65	III. System Protection & Control. C. Generation	M1	S1	3	Procedure by Sys Operator for reporting operation w/out automatic voltage control mode
		M2	S1	3	Log of operation w/out auto voltage control mode by gen owner
		M3	S2	3	Documentation of schedule for maintaining network voltage
		M4	S2	3	Log operation not maintaining network voltage schedules
		M5	S2	3	Reporting Procedures for tap settings of generator step-up & auxiliary transformers
		M6	S2	3	Tap settings Data of generator step-up & auxiliary transformers
		M7	S3	3	Requirements for withstanding temporary excursions in frequency, voltage, etc.

		M8	S4	3	Info on generator controls coordination with unit's short-term capabilities & protective relays
		M9	S5	3	Information on speed/load governing system
		M10	S6	3	Procedure to monitor/review/analyze/correct trip operations of generator protection equipment
		M11	S6	3	Documentation of all operations of generator protection equipment
		M12	S7	3	Maintenance/testing of generation equipment protection systems
66	III. System Protection & Control B. Transmission Control Devices	M1	S1	4	Assessment of reliability impact of transmission control devices
		M2	S1	4	Transmission control device models and data
		M3	S1	4	Periodic review & validation of settings & operating strategies
67	III. System Protection & Control. D. Under Frequency Load Shedding	M1	S1	2	Develop/document Regional UFLS Program
		M2	S1	2	Consistency of entities with Regional UFLS program
		M3	S1	2	Document/implement UFLS maintenance/testing Program
		M4	S1	2	Analysis & documentation of UFLS Event
68	III. Sys Protection & Control E. Under Voltage Load Shed	M1	S1-S2	3	Documentation of undervoltage load shedding program
		M2	S1	3	UVLS Regional Database
		M3	S1-S2	3	Assess design and effectiveness of UVLS programs

		M4	S1	3	Document/implement UVLS maintenance/testing Program
		M5	S1	3	Analysis & documentation of UVLS event
69	III. System Protection & Control. F. Special Protection Systems	M1	S1- S4	2	Document/implement Regional SPS review Process
		M2	S1- S3	2	SPS Database
		M3	S1- S3	2	Review, document & assessment of SPS Compliance to Stds
		M4	S1- S3	2	Compliance review & document new/proposed SPS installations
		M5	S4	2	Document/analyze misoperations
		M6	S5	2	Document/implement SPS maintenance/testing Program
70	IV. System Restoration A. Sys Blackstart Cap.	M1	S1	3	Regional blackstart capability Plan
		M2	S1	3	Demonstrate testing blackstart unit can perform its function.
		M3	S1	3	Diagram blackstart units & initial switching
		M4	S2	3	Document blackstart unit test results
71	IV. System Protection B. Automatic Restoration of Load	M1	S1	3	Document ALR programs including database
		M2	S1	3	Document ALR program with Regional requirements
		M3	S1	3	Assess effectiveness of automatic load restoration programs
		M4	S1	3	Document ALR equipment testing/maintenance program
72	Vegetation Management	N/A	none	N/A	Vegetation Management



**COMMENT FORM PART 2 – QUESTIONNAIRE**  
**Draft 1 of Proposed Version 0 Reliability Standards**

This form is to be used to submit comments on Draft 1 of the Version 0 Reliability Standards. Comments must be submitted by **August 9, 2004**. You may submit the completed form by emailing it to: [sarcomm@nerc.com](mailto:sarcomm@nerc.com) with the words “Version 0 Comments” in the subject line. If you have questions please contact Gerry Cauley at [gerry.cauley@nerc.net](mailto:gerry.cauley@nerc.net) on 609-452-8060.

[illegible]

**Question 1:**

Recognizing the Draft 1 Version 0 Standards as a preliminary work in progress that will continue to be refined by the Drafting Team in response to industry comments, if you were asked today to consider voting to approve (single block vote) the Version 0 Standards as presented, how do you think you would vote?

- ☐ Would approve the standards conditionally, assuming acceptable improvements are made in response to comments.
- ☐ Would not approve the standards.
- ☐ Would abstain.

Comments

**Question 2:**

Are there any “show stoppers” in the approach or results to date that would prevent you from approving the standards? If so, what are they?

Comments

**Question 3:**

As a whole, do you agree that the content of the Draft 1 Version 0 Standards is a reasonable translation of existing NERC reliability rules that does not significantly change current reliability obligations? (You will have a chance to comment on individual standards and requirements later.)

- ☐ Agree.
- ☐ Disagree.

Comments

**Question 4:**

There are numerous areas where the Drafting Team found it could easily eliminate redundancies in the requirements across various standards and improve the standards by better grouping the requirements into logical areas. However, the Drafting Team resisted making those changes in the first draft to ensure the industry would be able to more easily visualize the mapping from the existing documents to the Version 0 Standards. Should the Drafting Team minimize changes to eliminate redundancies and improve organization of the standards, or should the team make those improvements in Version 0?

- ☐ Make improvements to reduce redundancies and better group the requirements.
- ☐ Minimize the changes to simplify the transition from existing rules to Version 0.

Comments

**Question 5:**

As a whole, do you agree that the designation of functions in the Functional Model is acceptable? (You will have a chance to comment on individual standards and requirements later.)

- ☐ Agree.
- ☐ Disagree.

Comments

**Question 6:**

The operating policies make frequent reference to Operating Authorities as being the accountable entities. In adopting the Functional Model into the Version 0 standards, the Drafting Team had to make numerous extrapolations of the intent of the operating policies. For the most part, the requirements are addressed to Reliability Authorities, Balancing Authorities, and Transmission Operators. As needed, requirements specify Generator Operators, Transmission Service Providers, Load Serving Entities, and Purchasing-Selling Entities.

The Drafting Team seeks comments on whether the references to Operating Authorities should include these other functions when appropriate, or should an assumption be made in Version 0 that the reliability obligations of these other functions are addressed in service agreements.

- ☐ Include these other functions as appropriate in a specific requirement.
- ☐ Do not include these functions in the requirements.

Comments

**Question 7:**

No potential business practice standards were identified in the Version 0 planning standards. In translation of the operating policies, areas were identified where business practices could potentially be developed. However, the Drafting Team felt that the reliability requirements and business practices are so intertwined that to separate them would require substantial revisions to the requirements that would exceed the mandate of “no changes to the reliability rules in Version 0.” The Drafting Team identified the following areas in which it would recommend business practices be developed in Version 0:

- Operating Policy 1D (including Appendix 1D) — Time error correction procedures, except the ability of the Reliability Authority to halt a time error correction for reliability considerations.
- Operating Policy 1F — Inadvertent energy payback, except that inadvertent energy accounting remains a reliability requirement.
- Operating Policy 3 and Appendices 3A1, 3A2, 3A3, and 3A4 — Tagging procedures, E-Tag specifications and other sections of Operating Policy 3. Essential requirements to tag transactions and tag timing requirements remain reliability standards.

As a whole, do you agree that this allocation of potential business practice standards? (You will have a chance to comment on individual standards and requirements later.)

☐ Agree.

☐ Disagree

Comments

**Question 8:**

The Drafting Team seeks inputs on any other policies, standards, or appendices that should be considered as business practices in Version 0 and removed from the NERC standards. Please identify the policy, appendix, or planning standard by number and name and state your reason for recommending that material become a business practice standard in Version 0.

Comments

**Question 9:**

The Drafting Team is recommending a partial implementation of the Functional Model by assuming all of the Reliability Coordinator requirements in current policy should be assigned to Reliability Authorities. The Drafting Team believes implementation is simplest if the existing Reliability Coordinators are registered as the Reliability Authorities. However, this approach is flexible to accommodate regions in which existing control areas are deemed to be Reliability Authorities. In these regions, the Reliability Authority may delegate tasks “upward” to a Reliability Coordinator organization, although the registered Reliability Authority would retain accountability for complying with all of the applicable standards.

Do you agree with this approach?

☐ Agree.

☐ Disagree.

Comments

**Question 10:**

The Drafting Team recommends that the Interchange Authority function not be adopted in the Version 0 standards. To do so would require changes to tools and procedures, as well as reliability obligations. The Drafting Team recommends retaining the BA to BA scheduling method in current practice until new standards can be developed later for adopting the Interchange Authority function.

Do you agree with this approach?

☐ Agree.

☐ Disagree.

Comments

**Question 11:**

During the posting of the Version 0 SAR, some commenters indicated that planning standards that had not been completely field-tested should not be included in Version 0. Phase 3 planning standards were field-tested but no changes were made to these standards following the field tests. The results of the Phase 3 field tests were mixed — several measures need only minor changes, and other measures need more significant changes. The compliance templates just approved by the NERC Board in April 2004 do include some of the Phase 3 planning standards. Any Phase 3 planning standard that was approved for full implementation by the board is assumed to be accepted by the industry, and is proposed for inclusion in Version 0. If the industry indicates there are measures that need additional work, these will be returned to the Planning Committee for additional work and re-submission through the new standards process. If a measure is removed, it will be “retired” when Version 0 is approved and can only be replaced by going through the new reliability standards process. At this point, all Phase 3 measures are included in the first draft of Version 0. Please indicate in the table below which Phase 3 measures you think should be kept or deleted from Version 0.

Version 0 Standard	Existing Planning Standard	Existing measure	Keep	Delete
57	I. System Adequacy & Security. F. Disturbance Monitoring	M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
		M4	<input type="checkbox"/>	<input type="checkbox"/>
65	III. System Protection & Control. C. Generation	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
		M4	<input type="checkbox"/>	<input type="checkbox"/>
		M5	<input type="checkbox"/>	<input type="checkbox"/>
		M6	<input type="checkbox"/>	<input type="checkbox"/>
		M7	<input type="checkbox"/>	<input type="checkbox"/>
		M8	<input type="checkbox"/>	<input type="checkbox"/>
		M9	<input type="checkbox"/>	<input type="checkbox"/>
		M10	<input type="checkbox"/>	<input type="checkbox"/>
		M11	<input type="checkbox"/>	<input type="checkbox"/>
		M12	<input type="checkbox"/>	<input type="checkbox"/>
68	III. Sys Protection & Control E. Under Voltage Load Shed	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M5	<input type="checkbox"/>	<input type="checkbox"/>
70	IV. System Restoration A. Sys Blackstart Cap.	M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
71	IV. System Protection B. Automatic Restoration of Load	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
		M4	<input type="checkbox"/>	<input type="checkbox"/>

Comments

**Question 12:**

During the posting of the Version 0 SAR, some commenters indicated that Planning Standards that had not been field-tested should not be included in Version 0. None of the Phase 4 Planning Standards were field-tested. If the industry indicates there are measures that need additional work, these will be returned to the Planning Committee for additional work and re-submission through the new standards process. At this point, all Phase 4 Measures are included in the 1st draft of Version 0. Please indicate in the table below which Phase 3 measures you think should be kept or deleted from Version 0.

<b>Version 0 Standard</b>	<b>Existing Planning Standard</b>	<b>Existing measure</b>	<b>Keep</b>	<b>Delete</b>
64	I. System Adequacy & Security D. Voltage Support and Reactive Power	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
57	I. System Adequacy & Security. F. Disturbance Monitoring	M5	<input type="checkbox"/>	<input type="checkbox"/>
59	II. System Modeling Data B. Generation Equipment	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
		M4	<input type="checkbox"/>	<input type="checkbox"/>
		M5	<input type="checkbox"/>	<input type="checkbox"/>
		M6	<input type="checkbox"/>	<input type="checkbox"/>
61	II. System Modeling Data D. Actual & Forecast Demands	M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
62	II. System Modeling Data E. Demand Characteristics (Dynamic)	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>
66	III. System Protection & Control B. Transmission Control Devices	M1	<input type="checkbox"/>	<input type="checkbox"/>
		M2	<input type="checkbox"/>	<input type="checkbox"/>
		M3	<input type="checkbox"/>	<input type="checkbox"/>

Comments



**Question 13:**

Please comment on any specific proposed Version 0 Standards for which you have a concern. In doing so, please recognize that the Drafting Team is limited in scope to translating existing reliability rules and identifying functions and business practices.

<b>Standard #</b>	<b>Section # (Planning Only)</b>	<b>Requirement or Measure #</b>	<b>Comments</b>

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

Standard #	Section # (Planning Only)	Requirement or Measure #	Comments



Standard #	Section # (Planning Only)	Requirement or Measure #	Comments

**Question 14:**

Please provide any additional comments you have regarding the Draft 1 Version 0 Reliability Standards.

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	001	<p>Policy 1 – Generation Control and Performance: Section A Control Performance Standard</p> <p>Appendix 1A, Area Control Error (ACE) Equation</p> <p>Performance Standard Reference Document</p> <p>P1T1 Compliance Template</p>	<p>The Drafting Team has translated CPS1 and CPS2 to adopt the BALANCING AUTHORITY function. Otherwise requirements are unchanged.</p> <p>To make the standard complete, relevant equations from Appendix 1A have been included in the requirements below.</p> <p>To make the standard complete, requirements and equations from the Performance Standard Reference Document have been incorporated.</p>
Title	Real Power Balancing Control Performance		
Purpose	To maintain Interconnection frequency within defined limits by balancing real power demand and supply in real-time.	Policy 1 Introduction	
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Requirements	<p>R1 A BALANCING AUTHORITY shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the BALANCING AUTHORITY AREA's ACE divided by 10B (B is the clock-minute average of the BALANCING AUTHORITY AREA's frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION's FREQUENCY ERROR is less than a specific limit. This limit <math>\epsilon_1^2</math> is a constant derived from a targeted frequency bound (separately calculated for each INTERCONNECTION) reviewed and set as necessary by the NERC Operating Committee.</p> $AVG_{Period} \left[ \left( \frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right] \leq \epsilon_1^2 \text{ or } \frac{AVG_{Period} \left[ \left( \frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right]}{\epsilon_1^2} \leq 1$	Policy 1A Requirement 1.1	<p>This is the current CPS1 standard.</p> <p>Drafting Team assumes NERC Operating Committee is the authority to set and approve epsilon for each interconnection. Policy currently references the Resources Subcommittee.</p>
	<p>R2 A BALANCING AUTHORITY shall operate such that its Area's average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as <math>L_{10}</math>.</p> $AVG_{10\text{-minute}}(ACE_i) \leq L_{10}$ <p>where:</p> $L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}$ <p><math>\epsilon_{10}</math> is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year. The bound, <math>\epsilon_{10}</math>, is the same for every BALANCING AUTHORITY AREA within an Interconnection, and <math>B_s</math> is the sum of the frequency bias settings of the balancing areas in the respective Interconnection. For BALANCING AUTHORITY AREAS with variable bias, this is equal to</p>	Policy 1A Requirement 1.2	This is the current CPS2 standard.

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	the sum of the minimum frequency bias settings.		
	R3 A BALANCING AUTHORITY providing OVERLAP REGULATION SERVICE shall evaluate Requirement 1 (CPM1) and Requirement 2 (CPM2) using the characteristics of the combined ACE and combined FREQUENCY BIAS SETTINGS.	Policy 1A Requirement 2.4	
	R4 A BALANCING AUTHORITY receiving OVERLAP REGULATION SERVICE shall not have its control performance evaluated (i.e. from a control performance perspective, the BALANCING AUTHORITY has shifted all control requirements to the BALANCING AUTHORITY providing OVERLAP REGULATION SERVICE).	Policy 1A Requirement 2.5	
Measures	<p>M1 A BALANCING AUTHORITY shall achieve, as a minimum, Requirement 1 compliance of 100% (CPM1). CPM1 is calculated by converting a compliance ratio to a compliance percentage as follows:  <math display="block">CPR1 = (2 - CF) * 100\%</math> The frequency-related Compliance Factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the TARGET FREQUENCY BOUND:  <math display="block">CF = \frac{CF_{12\text{-month}}}{(\epsilon_1)^2}</math></p> <p>where: Epsilon 1 is defined in Requirement 1.</p> <p>The rating index <math>CF_{12\text{-month}}</math> is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, frequency error and FREQUENCY BIAS SETTINGS.</p> <p>A clock-minute average is the average of the reporting BALANCING AUTHORITY's valid measured variable (i.e., for ACE and for frequency error for each sampling cycle during a given clock-minute.</p>	<p>Policy 1A Requirement 2.1</p> <p>Performance Standards Reference Document</p> <p>P1A Requirement 2.1.1</p>	

Proposed Draft Version 0 Standard Language	Existing Document References	Comments
$\left( \frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left( \frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right)}{-10B}$ $\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$ <p>The BALANCING AUTHORITY's clock-minute Compliance Factor (CF) becomes:</p> $CF_{\text{clock-minute}} = \left[ \left( \frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$ <p>Normally, sixty (60) clock-minute averages of the reporting area's ACE and of the respective Interconnection's frequency error will be used to compute the respective Hourly Average Compliance parameter.</p> $CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$ <p>The reporting entity shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., HE 0100, HE 0200, ..., HE 2400).</p> $CF_{\text{clock-hour average month}} = \frac{\sum_{\text{days in month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute sample in clock-hour}})]}{\sum_{\text{days in month}} [n_{\text{one-minute sample in clock-hour}}]}$	<p>P1 A. 2.1.1.2</p> <p>P1 A. 2.1.1.3</p>	

Proposed Draft Version 0 Standard Language	Existing Document References	Comments
$CF_{\text{month}} = \frac{\sum_{\text{hours in day}} [(CF_{\text{clock hour average month}})(n_{\text{one-minute sample in clock hour averages}})]}{\sum_{\text{hours in day}} [n_{\text{one-minute sample in clock hour averages}}]}$ <p>The 12-month Compliance Factor becomes:</p> $CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$ <p>In order to ensure that the average ACE and FREQUENCY DEVIATION calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and FREQUENCY DEVIATION samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or FREQUENCY DEVIATION due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and FREQUENCY DEVIATION, that one-minute interval shall be excluded from the calculation of CPM1.</p>	<p>P1 A. 2.1.2</p>	
<p>M2 A BALANCING AUTHORITY shall achieve, as a minimum, Requirement 2 compliance of 90% (CPM2). CPM2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:</p> $CPS2 = \left[ 1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$ <p>The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L<sub>10</sub>. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.</p>	<p>Policy 1A Requirement 2.2</p> <p>Performance Standards Reference Document</p>	<p>Remove unnecessary capitalization.</p>

Proposed Draft Version 0 Standard Language	Existing Document References	Comments
<p>Violation clock-ten-minutes</p> $\left  \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right  \leq L_{10}$ <p>= 0 if</p> $\left  \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right  > L_{10}$ <p>= 1 if</p> <p>Each BALANCING AUTHORITY shall report the total number of violations and unavailable periods for the month. <math>L_{10}</math> is defined in Standard 002.</p> <p>Since CPM2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.</p> <p>A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.</p> <p>In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPM2.</p> <p>A BALANCING AUTHORITY providing or receiving SUPPLEMENTAL REGULATION SERVICE through DYNAMIC TRANSFER shall continue to be evaluated on the characteristics of its own ACE with the SUPPLEMENTAL REGULATION SERVICE included.</p>	<p>Policy 1A Requirement 2.2.1</p> <p>Policy 1A Requirement 2.2.2</p> <p>P1 A. 2.2.2.1</p> <p>P1 A 2.3</p>	



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Regional Differences	The ERCOT waiver approved by the NERC Operating Committee on November 21, 2002, is a part of Standard 001 by reference.		ERCOT has an existing waiver to CPS2
Compliance Monitoring Process	<p>Compliance with the CPM 1 standard shall be measured on a percentage basis as set forth in the NERC Performance Standard Training Document.</p> <p>Control Areas must have achieved the minimum compliance level and must send one completed copy of the CPM 1 and CPM 2 form “NERC Control Performance Standard Survey-All Interconnections” each month to the Regions as per established dates.</p> <p>The Regional Reliability Council must submit a summary document reporting compliance with CPM 1 and CPM 2 to NERC no later than the 20th day of the following month.</p> <p>Periodic Compliance Monitoring: Compliance for CPM 1 and CPM 2 will be evaluated for each reporting period.</p> <p>The data that supports the calculation of CPM 1 and CPM 2 are to be retained in electronic form for at least a one-year period. If the CPM 1 and CPM 2 data for a BALANCING AREA are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (<math>ACE_i</math>), one-minute average frequency error, and, if using variable bias, one-minute average frequency bias.</p> <p>The reset period is one calendar month without a violation.</p> <p>On a regular basis, a BALANCING AUTHORITY shall submit performance standard surveys to monitor the BALANCING AUTHORITY’s control performance during normal and disturbance situations.</p> <p>A Balancing Authority shall submit a CPS Survey to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the month. The Resources Subcommittee Survey Contact shall</p>	<p>P1T1 Compliance Template</p> <p>Appendix 1H Section I.</p>	<p>The Drafting Team proposes to remove the compliance monitoring process from the Version 0 standards. Information in the compliance template is shown here for reference.</p>

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	submit the CPS survey to NERC no later than the 20th day following the end of the month.		
Levels of Non Compliance	<p>Non-compliance for CPM 1 and CPM 2 is evaluated separately. Non-compliance for CPM 1 in a month shall mean that the rolling twelve month average of CPM 1 ending in that month is less than 100%. Non-compliance for CPM 2 shall mean that the monthly CPM 2 average is below 90%. Both CPM 1 and CPM 2 are calculated and evaluated monthly.</p> <p><b>CPM 1</b></p> <p>Level 1 — The Control Area’s value of CPM 1 is less than 100% but greater than or equal to 95%.</p> <p>Level 2 — The Control Area’s value of CPM 1 is less than 95% but greater than or equal to 90%.</p> <p>Level 3 — The Control Area’s value of CPM 1 is less than 90% but greater than or equal to 85%.</p> <p>Level 4 — The Control Area’s value of CPM 1 is less than 85%.</p> <p><b>CPM2</b></p> <p>Level 1 — The Control Area’s value of CPM 2 is less than 90% but greater than or equal to 85%.</p> <p>Level 2 — The Control Area’s value of CPM 2 is less than 85% but greater than or equal to 80%.</p> <p>Level 3 — The Control Area’s value of CPM 2 is less than 80% but greater than or equal to 75%.</p> <p>Level 4 — The Control Area’s value of CPM 2 is less than 75%.</p>	P1T1	The Drafting Team proposes to retain the levels of non-compliance in Standard 001.

Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
Standard	002	Policy 1 – Generation Control and Performance: Section B Disturbance Control Standard  Performance Standard Reference Document  Compliance Template P1T2	This standard is a translation of the Disturbance Control Standard (DCS) to the functional model. Requirements have not been modified except to replace Control Area with BALANCING AUTHORITY or BALANCING AUTHORITY AREA.  For completeness, some requirements and equations from the Performance Standard Reference Document have been incorporated into the standard.
Title	Disturbance Control Performance		
Purpose	The BALANCING AUTHORITY demand-supply balance will quickly change following the sudden loss of load or generation failure. This results in a sudden change in the BALANCING AUTHORITY's ACE, and also a change in INTERCONNECTION frequency. The Disturbance Control Performance standard measures the BALANCING AUTHORITY's ability to utilize its CONTINGENCY RESERVES following a REPORTABLE DISTURBANCE. Because generator failures are far more common than significant losses of load and because CONTINGENCY RESERVE activation does not typically apply to the loss of load, the application of the Disturbance Control Performance standard is limited to the loss of supply and does not apply to the loss of load.	Policy 1B Introduction	
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. BALANCING AUTHORITIES</li> <li>2. RESERVE SHARING GROUPS (BALANCING AUTHORITIES may meet these requirements of Standard 002 through participation in a RESERVE SHARING GROUP.)</li> <li>3. Regional Reliability Organization</li> </ol>		

Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
Requirements	<p>R1 A BALANCING AUTHORITY shall have access to and/or operate CONTINGENCY RESERVES to respond to disturbances. CONTINGENCY RESERVES may be supplied from generation, controllable load resources, or coordinated adjustments to INTERCHANGE SCHEDULES.</p> <p>A BALANCING AUTHORITY may assign its CONTINGENCY RESERVE obligations to a RESERVE SHARING GROUP. In such cases, the RESERVE SHARING GROUP shall have the same responsibilities and obligations as each BALANCING AUTHORITY within it, with respect to monitoring and meeting the requirements of Standard 002.</p>	<p>Policy 1B Requirement 2.</p> <p>Paraphrased from the introduction to Policy 1B.</p>	
	<p>R2 Each Regional Reliability Organization, sub Regional Reliability Organization or RESERVE SHARING GROUP shall specify its CONTINGENCY RESERVE policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of OPERATING RESERVE – SPINNING and OPERATING RESERVE – SUPPLEMENTAL that may be included in CONTINGENCY RESERVE, and the procedure for applying CONTINGENCY RESERVE in practice, and the limitations, if any, upon the amount of interruptible load that may be included. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as CONTINGENCY RESERVE by multiple BALANCING AUTHORITIES.</p>	<p>Policy 1B Requirement 2.2</p> <p>Policy 1B Requirement 2.1</p>	
	<p>R3 Each BALANCING AUTHORITY or RESERVE SHARING GROUP shall activate sufficient CONTINGENCY RESERVE to comply with the Disturbance Control Performance Measure M1 (DCM). As a minimum, the BALANCING AUTHORITY or RESERVE SHARING GROUP shall carry at least enough CONTINGENCY RESERVE to cover the most severe single contingency. All BALANCING AUTHORITIES and RESERVE SHARING GROUPS shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.</p>	<p>P1 B. 2.3</p> <p>P1 B. 3. 3.1</p>	
	<p>R4 When a BALANCING AUTHORITY or RESERVE SHARING GROUP experiences a REPORTABLE DISTURBANCE, it is compliant with the DCM when the DISTURBANCE RECOVERY CRITERION is met within the DISTURBANCE RECOVERY PERIOD. Each BALANCING AUTHORITY or RESERVE SHARING GROUP shall meet the DCM 100%</p>	<p>P1 B. 3.2</p> <p>P1 B. 3.2.1</p>	

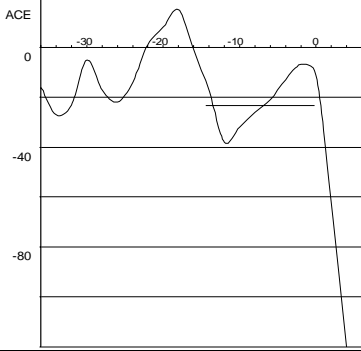
Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
	<p>of the time for REPORTABLE DISTURBANCES.</p> <p>A BALANCING AUTHORITY shall return its ACE to zero if its ACE just prior to the REPORTABLE DISTURBANCE was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-disturbance value. The default performance criterion described above may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Operating Committee.</p> <p>The default DISTURBANCE RECOVERY PERIOD is 15 minutes after the start of a REPORTABLE DISTURBANCE. This period may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Operating Committee.</p>	P1 B3.2.2	
R5	<p>A RESERVE SHARING GROUP shall comply with the DCM. A RESERVE SHARING GROUP shall be considered in a REPORTABLE DISTURBANCE condition whenever a group member has experienced a REPORTABLE DISTURBANCE and calls for the activation of CONTINGENCY RESERVES from one or more other group members. (If a group member has experienced a REPORTABLE DISTURBANCE but does not call for reserve activation from other members of the RESERVE SHARING GROUP, then that member shall report as a single BALANCING AUTHORITY.) Compliance may be demonstrated by either of the following two methods:</p> <p>The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance to the DCM. To be in compliance, the group ACE (or its equivalent) must meet the DISTURBANCE RECOVERY CRITERION after the schedule change(s) related to reserve sharing have been fully implemented, and within the DISTURBANCE RECOVERY PERIOD.</p> <p>or</p> <p>The RESERVE SHARING GROUP reviews each member's ACE in response to the activation of reserves. To be in compliance, a</p>	<p>P1 B. 3.3</p> <p>P1 B. 3.3.1</p> <p>P1 B. 3.3.2</p>	

Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
	member's ACE (or its equivalent) must meet the DISTURBANCE RECOVERY CRITERION after the schedule change(s) related to reserve sharing have been fully implemented, and within the DISTURBANCE RECOVERY PERIOD.		
	<p>R6 A Balancing Authority shall fully restore its CONTINGENCY RESERVES within the CONTINGENCY RESERVE RESTORATION PERIOD for its INTERCONNECTION. The CONTINGENCY RESERVE RESTORATION PERIOD begins at the end of the DISTURBANCE RECOVERY PERIOD.</p> <p>The BALANCING AUTHORITY or RESERVE SHARING GROUP shall restore its CONTINGENCY RESERVES within 90 minutes. This period may be adjusted to better suit the reliability targets of the INTERCONNECTION based on analysis approved by the NERC Operating Committee.</p>	<p>P1 B. 4.</p> <p>P1 B. 4.1</p> <p>P1 B. 4.2</p>	

Proposed Draft Version 0 Standard Language	Existing Document Reference	Comments
<div data-bbox="153 170 273 194" data-label="Text"> <p>Measures</p> </div> <div data-bbox="357 170 1220 435" data-label="Text"> <p>M1 A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (<math>R_i</math>). For loss of generation:</p> </div> <div data-bbox="396 464 833 732" data-label="Figure"> </div> <div data-bbox="856 638 1251 787" data-label="Equation-Block"> <p>if <math>ACE_A &lt; 0</math> then</p> <math display="block">R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}}</math> </div> <div data-bbox="357 963 520 992" data-label="Text"> <p>if <math>ACE_A \geq 0</math></p> </div> <div data-bbox="357 1032 411 1060" data-label="Text"> <p>then</p> </div> <div data-bbox="357 1065 869 1149" data-label="Equation-Block"> <math display="block">R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%</math> </div> <div data-bbox="812 816 1247 1079" data-label="Figure"> </div>	<div data-bbox="1262 170 1499 329" data-label="Text"> <p>P1 B. 6.1 Originally from the Performance Standard Reference Document.</p> </div>	

Proposed Draft Version 0 Standard Language	Existing Document Reference	Comments
<p>where:  <math>MW_{LOSS}</math> is the MW size of the Disturbance as measured at the beginning of the loss,  <math>ACE_A</math> is the pre-disturbance ACE,  <math>ACE_M</math> is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance event. A Balancing Authority or reserve sharing group may, at their discretion, set <math>ACE_M = ACE_{15 \text{ min}}</math>, and  <math>ACE_m</math> is the minimum algebraic value of ACE measured within the fifteen minutes following the Disturbance event. A Balancing Authority or reserve sharing group may, at their discretion, set <math>ACE_m = ACE_{15 \text{ min}}</math>.</p> <p><b>Determination of <math>MW_{LOSS}</math>.</b>  Record the <math>MW_{LOSS}</math> value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.</p> <p><b>Determination of <math>ACE_A</math>.</b>  Base the value for <math>ACE_A</math> on the average ACE over the period just prior to the start of the Disturbance. Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE. In the illustration to the right, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of <math>ACE_A = -25 \text{ MW}</math>.</p> <p><b>Determination of <math>ACE_M</math> or <math>ACE_m</math>.</b>  <math>ACE_m</math> is the maximum value of ACE measured within fifteen minutes following a given disturbance. At the discretion of the Balancing Authority or of the Reserve Sharing Group, compliance may be based on the ACE measured fifteen minutes following the Disturbance, i.e., <math>ACE_M = ACE_{15 \text{ min}}</math>.</p> <p><math>ACE_m</math> is the minimum value of ACE measured within fifteen minutes following a given disturbance. At the discretion of the Balancing Authority or of the Reserve Sharing Group, compliance may be based on the ACE measured fifteen minutes following the</p>	<p>6.1.1</p> <p>6.1.2</p> <p>6.1.3</p> <p>6.2</p>	



Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
			
Regional Differences			
Compliance Monitoring Process	<p>Compliance with the Disturbance Control Standard (DCS) shall be measured on a percentage basis as set forth in the NERC Performance Standard Training Document.</p> <p><b>Periodic Review</b>  CONTROL AREAS and/or RESERVE SHARING GROUPS must return one completed copy of DCS form “NERC Control Performance Standard Survey-All Interconnections” each quarter to the Region as per set dates.</p> <p>The Regional Reliability Council must submit a summary document reporting compliance with DCS to NERC no later than the 20<sup>th</sup> day of the month following the end of the quarter.</p> <p><b>Periodic Compliance Monitoring</b>  Compliance for DCS will be evaluated for each reporting period.</p> <p>Each BALANCING AUTHORITY or RESERVE SHARING GROUP shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Resources Subcommittee Survey Contact shall submit the survey to NERC</p>	P1T2	

Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
	no later than the 20th day following the end of the calendar quarter.		
Measuring Responsibility	Regional Reliability Council	P1T2	
Full Compliance	CONTROL AREA or RESERVE SHARING GROUP returned the ACE to zero or to its pre-disturbance level within the DISTURBANCE RECOVERY PERIOD, following the start of all Reportable Disturbances. DCS is calculated quarterly and compliance evaluated as the Average Percentage Recovery (APR) as defined in the Performance Standard Training Document.	P1T2	
Levels of Non Compliance	Each Balancing Authority or Reserve Sharing Group not meeting the Disturbance Control Standard during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Region Compliance Monitor . [e.g. For the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the Disturbance Control Standard in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the Most Severe Single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate Disturbance Control Performance Adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.	P1 B. 5.  P1 B. 7.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document Reference</b>	<b>Comments</b>
Levels of Non Compliance	<p>Level 1— Value of APR is less than 100% but greater than or equal</p> <p>Level 2 — Value of APR is less than 95% but greater than or equal to 90%.</p> <p>Level 3 — Value of APR is less than 90% but greater than or equal to 85%.</p> <p>Level 4 — Value of APR is less than 85%.</p>	P1T2	
Reset Period	One calendar quarter without a violation.	P1T2	
Data Retention	The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a RESERVE SHARING GROUP and CONTROL AREA are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.	P1T2	

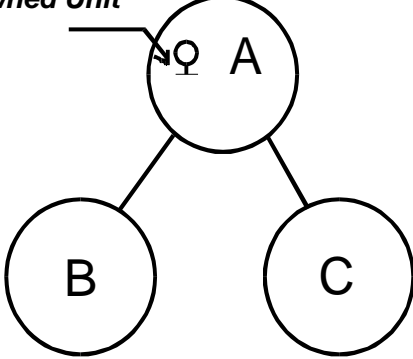
Proposed Draft Version 0 Standard Language		Existing Document Reference	Comments
Supporting Notes	<p>Reportable Disturbances. Reportable Disturbances are contingencies that are greater than or equal to 80% of the Most Severe Single Contingency loss. Region may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.</p> <p>Treatment of Multiple Contingencies.</p> <p>Simultaneous Contingencies. Multiple contingencies occurring within one minute or less of each other shall be treated as a single contingency. If the combined magnitude of the multiple contingencies exceeds the Most Severe Single Contingency, the loss shall be reported, but excluded from compliance evaluation.</p> <p>Multiple Contingencies within the Reportable Disturbance period. Additional contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.</p> <p>Multiple Contingencies within the Contingency Reserve Restoration Period. Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.</p>	<p>P1 B. 3.4</p> <p>P1 B. 3.5.1</p> <p>P1 B. 3.5.2</p> <p>P1 B. 3.5.3</p>	

**Information from Policy not included**

**Information from Compliance Template not included**

<b>DCS DATA</b>	<b>Description</b>	<b>Retention Requirements</b>
MW loss	The MW size of the disturbance as measured at the beginning of the loss.	Retain the value of MW loss used in DCS calculation.
ACEA	The pre-disturbance ACE.	Retain the value of ACEA used in DCS calculation.
ACEM	The maximum algebraic value of ACE measured within ten minutes following the disturbance event.	Retain the value of ACEM used in the DCS calculation.
ACE <sub>m</sub>	The minimum algebraic value of ACE measured within the recovery period following the disturbance event.	Retain the value of ACE <sub>m</sub> used in the DCS calculation.
Date of incident	The date the incident occurred.	Retain the date.
Time of incident	The time of the incident in hours, minutes, and seconds.	Retain the time as precise as possible.
Description of incident	Describe the incident in sufficient details to define the incident.	Retain sufficient details to define the incident, i.e. name and MW output of unit that tripped. Cause of incident.
Recovery Time Duration	The duration of time of the incident in hours, minutes, and seconds to have the ACE return to 0.	Retain the incident time as precise as possible.

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	003	Policy 1 – Generation Control and Performance Section C Frequency Response and Bias	
Title	Frequency Response and Bias		
Purpose	A standard method for setting BIAS is necessary to calculate the frequency bias component of ACE.		
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES		
Requirements	<p>R1 Each BALANCING AUTHORITY shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic. The BALANCING AUTHORITY may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change. Each BALANCING AUTHORITY shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee. Each BALANCING AUTHORITY shall establish and maintain a Frequency Bias Setting that closely matches or is greater than its system response.</p>	<p>Policy 1C Requirement 1.</p> <p>Policy 1C Requirement 1.1</p> <p>Policy 1C Requirement 1.2</p> <p>Policy 1C Requirement 1.3</p>	
	<p>R2 Each BALANCING AUTHORITY shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability. The criteria for tie-line bias control follow:</p> <ul style="list-style-type: none"> <li>• The BALANCING AUTHORITY shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the BALANCING AUTHORITY's frequency response characteristic. Frequency bias may be calculated several ways: <ul style="list-style-type: none"> <li>○ The BALANCING AUTHORITY may use a fixed frequency bias value which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The BALANCING AUTHORITY shall determine the fixed value by observing and averaging the frequency response characteristic for several disturbances during on-peak hours.</li> <li>○ The BALANCING AUTHORITY may use a variable (linear or non-linear) bias value which is based on a variable</li> </ul> </li> </ul>	<p>Policy 1C Requirement 2.</p> <p>Policy 1C Requirement 2.1.</p> <p>Policy 1C Requirement 2.1.1</p> <p>Policy 1C Requirement 2.1.2</p>	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	function of tie-line deviation to frequency deviation. The BALANCING AUTHORITY shall determine the variable frequency bias value by analyzing frequency response as it varies with factors such as load, generation, governor characteristics, and frequency.		
R3	<p>BALANCING AUTHORITIES that use Dynamic Scheduling or Pseudoties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting. Fixed schedules for Jointly Owned Units mandate that the BALANCING AUTHORITY (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any BALANCING AUTHORITIES that have fixed schedules (B and C). The BALANCING AUTHORITIES that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit should not include their share of the governor droop response in their Frequency Bias Setting.</p> <p><b>Jointly Owned Unit</b></p>  <pre> graph TD     A((A)) --- B((B))     A --- C((C))   </pre>	Policy 1C Requirement 2.2	
R4	BALANCING AUTHORITIES that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the BALANCING AUTHORITY's estimated yearly peak demand per 0.1 Hz change. BALANCING AUTHORITIES that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	Policy 1C Requirement 2.3  Policy 1C Requirement 2.4	
R5	A BALANCING AUTHORITY that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the	Policy 1C Requirement 2.5	



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	frequency response of the entire area being controlled. A BALANCING AUTHORITY that is performing Supplemental Regulation Service shall not change its Frequency Bias Setting.		
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	004	Policy 1 – Generation Control and Performance Section D Time Control Standard	The Drafting Team recommends time error correction procedures become NAESB business practice standards, but the ability to halt a time error correction for reliability considerations should remain a reliability standard.
Title	Time Error Correction		
Purpose	INTERCONNECTION frequency is normally scheduled at 60.00 Hz and controlled to that value. The control is imperfect and over time the frequency will average slightly above or below 60.00 Hz resulting in electric clocks developing an error relative to true time. When the error exceeds pre-set limits, corrective action is taken by adjusting the scheduled frequency; a practice termed Time Error Correction.	Policy 1 Section D	
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES 2. RELIABILITY AUTHORITIES		
Requirements	R1 Any RELIABILITY AUTHORITY in an INTERCONNECTION shall have the authority to terminate a time error correction in progress for reliability considerations. Any RELIABILITY AUTHORITY may request the halt of a scheduled time error correction that has not begun. BALANCING AUTHORITIES that have reliability concerns with the execution of a time error correction shall notify their RELIABILITY AUTHORITY and request the termination of a time error correction in progress.	Policy 1D Requirement 4.	This requirement could be moved to Standard 038 on RELIABILITY AUTHORITY Current Day Operations, eliminating the need for this standard.
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	005	Policy 1 – Generation Control and Performance Section E Automatic Generation Control Standard	
Title	Automatic Generation Control		
Purpose	BALANCING AUTHORITIES utilize AUTOMATIC GENERATION CONTROL (AGC) to automatically direct the loading of REGULATING RESERVE. AGC is used to limit the magnitude of AREA CONTROL ERROR (ACE) variations to the CPS bounds. This standard contains requirements that apply to the BALANCING AUTHORITY AGC needed to calculate ACE and to routinely deploy the REGULATING RESERVE.		
Effective Date			
Applicability	<ol style="list-style-type: none"> <li>1. BALANCING AUTHORITIES</li> <li>2. GENERATOR OPERATORS</li> <li>3. TRANSMISSION OPERATORS</li> <li>4. LOAD SERVING ENTITIES</li> </ol>		
Requirements	R1 All GENERATOR OPERATORS, TRANSMISSION OPERATORS, and LOAD SERVING ENTITIES having load, generation, or transmission facilities operating in an INTERCONNECTION shall ensure that load, generation, or transmission facilities are included within the metered boundaries of a BALANCING AUTHORITY AREA.		
	R2 Each BALANCING AUTHORITY shall maintain regulating reserves that can be controlled by AGC to meet the Control Performance Measure.	Policy 1E Requirement 2.1	
	R3 A BALANCING AUTHORITY providing regulation service shall ensure that adequate metering, communications and control equipment are employed to prevent such service from becoming a BURDEN on the INTERCONNECTION or other BALANCING AUTHORITY AREAS.	Policy 1E Requirement 2.2.1	
	R4 A BALANCING AUTHORITY providing regulation service shall notify the host BALANCING AUTHORITY for whom it is controlling if it is unable to provide the service, as well as any intermediary BALANCING AUTHORITIES.	Policy 1E Requirement 2.2.2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	R5 A BALANCING AUTHORITY receiving regulation service shall ensure that backup plans are in place to provide replacement regulation service should the supplying BALANCING AUTHORITY no longer be able to provide this service.	Policy 1E Requirement 2.2.3	
	R6 The BALANCING AUTHORITY's Automatic Generation Control (AGC) shall compare total Net Actual Interchange to total Net Scheduled Interchange plus frequency bias obligation to determine the BALANCING AUTHORITY's Area Control Error (ACE). Single BALANCING AUTHORITIES operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a BALANCING AUTHORITY is unable to calculate ACE for more than 30 minutes it shall notify its RELIABILITY AUTHORITY. The BALANCING AUTHORITY shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the BALANCING AUTHORITY shall use manual control to adjust generation to maintain the Net scheduled Interchange.	Policy 1E Requirement 3.1  Policy 1E Requirement 3.2  Policy 1E Requirement 3.3	
	R7 The BALANCING AUTHORITY shall ensure that data-acquisition for and calculation of ACE occur at least every six seconds. Each BALANCING AUTHORITY shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.	Policy 1E Requirement 4.1  Policy 1E Requirement 4.2	
	R8 The BALANCING AUTHORITY shall include all INTERCHANGE SCHEDULES with ADJACENT BALANCING AUTHORITIES in the calculation of Net Scheduled Interchange for the Area Control Error (ACE) equation. BALANCING AUTHORITIES with an HVDC link to another BALANCING AUTHORITY connected asynchronously to their INTERCONNECTION may choose to omit the INTERCHANGE SCHEDULE related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	Policy 1E Requirement 4.3.1  Policy 1E Requirement 4.3.1.1	
	R9 The BALANCING AUTHORITY shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	Policy 1E Requirement 4.3.2	
	R10 BALANCING AUTHORITIES shall use agreed upon ramp rates in the	Policy 1E	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	Scheduled Interchange values to calculate ACE.	Requirement 4.3.3	
	R11 Each BALANCING AUTHORITY shall include all tie-line flows with ADJACENT BALANCING AUTHORITY Areas in the ACE calculation. BALANCING AUTHORITIES that share a tie shall ensure tie-line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. BALANCING AUTHORITIES shall ensure that MWh data is telemetered or reported at the end of each hour. BALANCING AUTHORITIES shall ensure the power flow and ACE signals that are utilized for calculating BALANCING AUTHORITY performance or that are transmitted for regulation service are not filtered prior to transmission, except for anti-aliasing filtering of tie lines. BALANCING AUTHORITIES shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more BALANCING AUTHORITIES to deliver the output of Jointly Owned Units or to serve remote load.	P1 E. 4.4.1  Policy 1E Requirement 4.4.2 Policy 1E Requirement 4.4.3  Policy 1E Requirement 4.4.4	
	R12 Each BALANCING AUTHORITY shall perform hourly error checks using tie-line MWh meters with common time synchronization to determine the accuracy of its control equipment. The BALANCING AUTHORITY shall adjust the component (e.g., tie line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.	Policy 1E Requirement 4.5.1  Policy 1E Requirement 4.5.2	
	R13 The BALANCING AUTHORITY shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the BALANCING AUTHORITY shall provide its operating personnel with real-time values for Area Control Error (ACE), INTERCONNECTION frequency and Net Actual Interchange with each ADJACENT BALANCING AUTHORITY AREA. The BALANCING AUTHORITY shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the BALANCING AUTHORITY's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	Policy 1E Requirement 4.6.1  Policy 1E Requirement 4.6.2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments												
	<p>R14 The BALANCING AUTHORITY shall sample data at least at the same periodicity with which ACE is calculated. The BALANCING AUTHORITY shall flag missing or bad data for operator display and archival purposes. The BALANCING AUTHORITY shall collect data coincident, to the greatest practical extent; i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time. The BALANCING AUTHORITY shall adhere to the minimum values for measuring devices as listed below:</p> <table><tr><td>Device</td><td>Accuracy</td></tr><tr><td>Digital frequency transducer</td><td>≤ 0.001 Hz</td></tr><tr><td>MW, MVAR, and voltage transducer</td><td>≤ 0.25 % of full scale</td></tr><tr><td>Remote terminal unit</td><td>≤ 0.25 % of full scale</td></tr><tr><td>Potential transformer</td><td>≤ 0.30 % of full scale</td></tr><tr><td>Current transformer</td><td>≤ 0.50 % of full scale</td></tr></table>	Device	Accuracy	Digital frequency transducer	≤ 0.001 Hz	MW, MVAR, and voltage transducer	≤ 0.25 % of full scale	Remote terminal unit	≤ 0.25 % of full scale	Potential transformer	≤ 0.30 % of full scale	Current transformer	≤ 0.50 % of full scale	Policy 1E Requirement 4.7.1 Policy 1E Requirement 4.7.2 Policy 1E Requirement 4.7.3 Policy 1E Requirement 4.7.4	
Device	Accuracy														
Digital frequency transducer	≤ 0.001 Hz														
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale														
Remote terminal unit	≤ 0.25 % of full scale														
Potential transformer	≤ 0.30 % of full scale														
Current transformer	≤ 0.50 % of full scale														
	<p>R15 Each BALANCING AUTHORITY shall at least annually check and calibrate its time error and frequency devices against a common reference.</p>	Policy 1E Requirement 5.													
Measures	Not Specified.														
Regional Differences	None Identified.														
Compliance Monitoring Process	<p>Data Retention:</p> <ul style="list-style-type: none"><li>Each BALANCING AUTHORITY shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, tie-line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.</li><li>Each BALANCING AUTHORITY or RESERVE SHARING GROUP shall retain documentation of the magnitude of each REPORTABLE DISTURBANCE as well as the ACE charts and/or samples used to calculate the BALANCING AUTHORITY’s or RESERVE SHARING GROUP’s disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.</li><li>BALANCING AUTHORITIES shall be prepared to supply data to</li></ul>	Policy 1E Requirement 4.8.1  Policy 1E Requirement 4.8.2  Policy 1E Requirement 4.8.3													

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>NERC in the industry standard format (defined below):</p> <ul style="list-style-type: none"> <li>○ Within one week upon request, BALANCING AUTHORITIES shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Deviation from Schedule.</li> <li>○ Within one week upon request, BALANCING AUTHORITIES shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Deviation from Schedule for a time period, from two minute prior to thirty minutes after the identified disturbance.</li> </ul>	<p>4.8.3.1</p> <p>4.8.3.2</p>	
Levels of Non Compliance	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	006	Policy 1 – Generation Control and Performance Section F Inadvertent Interchange	Inadvertent Interchange payback in-kind is being developed by NAESB as a business practice standard. The remaining requirements of Policy 1F are captured in this standard.
Title	Inadvertent Interchange		
Purpose	<p>This standard defines the requirements for capturing inadvertent data for the purpose of ensuring that reliability is not compromised by unscheduled flows. INADVERTENT INTERCHANGE provides a measure of non-scheduled INTERCHANGE and bilaterally scheduled inadvertent payback. These transfers are caused by such factors as BALANCING AUTHORITY AREA regulation and frequency response, metering errors in frequency and/or interchange measurements (either scheduled or actual), unilateral INADVERTENT INTERCHANGE payback and human errors.</p> <p>This standard defines a process for monitoring BALANCING AUTHORITIES to ensure that, over the long term, the BALANCING AUTHORITY AREAS do not excessively depend on other BALANCING AUTHORITY AREAS in the INTERCONNECTION for meeting their demand or INTERCHANGE obligations.</p>		
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES		
Requirements	R1 A BALANCING AUTHORITY shall calculate and record hourly INADVERTENT INTERCHANGE.	Policy 1F Requirement 1.	
	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.	Policy 1F Requirement 2.	
	R3 A BALANCING AUTHORITY shall ensure all of its BALANCING AUTHORITY AREA interconnection points are equipped with common MWh meters, with readings provided hourly to the control centers of both ADJACENT BALANCING AUTHORITIES.	Policy 1F Requirement 3.	
	R4 ADJACENT BALANCING AUTHORITY AREAS shall operate to a	Policy 1F	



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>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:</p> <p>Each BALANCING AUTHORITY, by the end of the next business day, shall agree with its ADJACENT BALANCING AUTHORITIES to:</p> <p>The hourly values of NET INTERCHANGE SCHEDULE.</p> <p>The hourly integrated MWh values of NET ACTUAL INTERCHANGE</p> <p>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.</p> <p>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(s).</p>	<p>Requirement 4.</p> <p>Policy 1F Requirement 4.1</p> <p>Policy 1F Requirement 4.2</p> <p>Policy 1F Requirement 4.3</p>	
	<p>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 Resources Subcommittee Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures."</p>	Policy 1F Requirement 6.2	The Drafting Team recommends that a separate dispute resolution procedure not be maintained.
Regional	None Identified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Differences			
Compliance Monitoring Process	Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange as detailed in Appendix 1F, “Inadvertent Interchange Energy Accounting Practices and Dispute Resolution Process.” These summaries shall not include any after-the-fact changes that were not agreed to by the Source BALANCING AUTHORITY, Sink BALANCING AUTHORITY and all Intermediary BALANCING AUTHORITY(s).	Policy 1F Requirement 6.	
	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.	Policy 1F Requirement 6.1	
	Each BALANCING AUTHORITY shall submit its monthly summary report to its Resources Subcommittee Survey Contact by the 15th calendar day of the following month. The Resources Subcommittee Survey Contact will prepare a composite tabulation and submit that tabulation to the NERC staff by the 22nd calendar day of the month.	Policy 1F Requirement 6.2	
	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.	Policy 1G Requirement 1.1	
	Each Region shall prepare an Inadvertent Interchange summary monthly to monitor the BALANCING AUTHORITIES’ monthly INADVERTENT INTERCHANGE and all-time accumulated INADVERTENT INTERCHANGE. Each Region shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.		
Levels of Non Compliance	A BALANCING AUTHORITY that neither submits a report to the Resources Subcommittee 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.	Policy 1F Requirement 6.2.1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	007	Policy 2 — Transmission Section A Transmission Operations	
Title	Transmission Security		
Purpose	To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency and specified multiple contingencies.		
Effective Date			
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS		
Requirements	R1 A TRANSMISSION OPERATOR shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Policy 2A	
	R2 A TRANSMISSION OPERATOR shall, when practical, operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Regional Reliability Council policy.	Policy 2A Requirement 1.1	The vagueness of the multiple outage criteria referenced here should be addressed in Version 1.
	R3 RELIABILITY AUTHORITIES and TRANSMISSION OPERATORS, individually and jointly, shall develop, maintain, and implement formal policies and procedures to provide for transmission security. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional security, including: <ul style="list-style-type: none"> <li>• Equipment ratings</li> <li>• Monitoring and controlling voltage levels and real and reactive power flows</li> <li>• Switching transmission elements</li> </ul>	Policy 2A Requirement 1.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
	<ul style="list-style-type: none"> <li>Planned outages of transmission elements</li> <li>Development of Interconnected Reliability Operating Limits and System Operating Limits</li> <li>Responding to Interconnected Reliability Operating Limits and System Operating Limit violations.</li> </ul>		
Measures	Not Specified		
Regional Differences	Not Identified		
Compliance Monitoring Process	Not Specified		
Levels of Non Compliance	Not Specified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	008	Policy 2 Transmission Section A Transmission Operations  Compliance Template P2T1	
Title	Reporting System Operating Limit (SOL) and Interconnected Reliability Operating Limit (IROL) Violations		
Purpose	This standard requires SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL) violations to be reported to other reliability entities, so that affected entities may take necessary actions to protect the reliability of their systems and the INTERCONNECTION.		
Effective Date	February 8, 2005		
Applicability	1. TRANSMISSION OPERATORS 2. BALANCING AUTHORITIES		
Requirements	R1 A TRANSMISSION OPERATOR shall inform its RELIABILITY AUTHORITY when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	Compliance Template P2T1	
	R2 Following a contingency or other event that results in an INTERCONNECTED RELIABILITY OPERATING LIMIT violation, the TRANSMISSION OPERATOR shall return its transmission system to within IROL as soon as possible, but no longer than 30 minutes.	Policy 2A Requirement 2	The Drafting Team adopted policy language over the compliance template here because the policy was more conservative with respect to reliability. This requirement is also consistent with Policy 9E Requirement 1.4.4.
	R3 A TRANSMISSION OPERATOR shall take all appropriate action up to and including shedding of firm load in order to comply with Requirement 2 above.	Policy 2A Requirement 1.2	
	R4 The RELIABILITY AUTHORITY shall evaluate actions taken to address an SOL or IROL violation and, if the actions taken are not appropriate or sufficient, direct actions as required to the TRANSMISSION OPERATOR or BALANCING AUTHORITY to return the	Compliance Template P2T2 Policy 2A Requirement 1.1	

**Version 0 – Draft 1 for Public Comment**

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	system to within limits.		
	R5 The RELIABILITY AUTHORITY shall report each IROL violation that exceeds 30 minutes in duration to the Regional Reliability Organization and NERC within 72 hours.	Policy 2A Requirement 2.1.1	This should be considered as a compliance monitoring or administrative procedure rather than a standard.
Measures	<p>Evidence that the TRANSMISSION OPERATOR informed the RELIABILITY AUTHORITY when an IROL or SOL was exceeded and the actions they took to return the system to within limits.</p> <p>Evidence that the TRANSMISSION OPERATOR returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.</p> <p>Evidence that the Reliability Authority evaluated actions and provided direction as required to the Control Area Operator or Transmission Operator to return the system to within limits.</p>	Compliance Template P2T1	
Regional Differences	None Identified		
Compliance Monitoring Process	<p>A TRANSMISSION OPERATOR shall report to its RELIABILITY AUTHORITY all occurrences in which an INTERCONNECTED RELIABILITY OPERATING LIMIT or SYSTEM OPERATING LIMIT is exceeded.</p> <p>The RELIABILITY AUTHORITY shall report any IROL violation or any SOL violation exceeding 30 minutes to the Regional Reliability Organization. The Reliability Authority shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:</p> <ol style="list-style-type: none"> <li>1) System instability;</li> <li>2) Unacceptable system dynamic response or equipment tripping;</li> <li>3) Voltage levels in violation of applicable emergency limits;</li> <li>4) Loadings on transmission facilities in violation of applicable emergency limits;</li> <li>5) Unacceptable loss of load based on regional and/or NERC</li> </ol>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>criteria.</p> <p>Each Regional Reliability Organization shall report any such violations of to NERC via the NERC Compliance Reporting process.</p> <p>The data retention period is three months.</p> <p>The reset period is monthly.</p> <p>RELIABILITY COORDINATORS shall report to its Regional Reliability Council any occurrences where an IROL violation extended beyond 30 minutes. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>		
Levels of Non Compliance	<p>The TRANSMISSION OPERATOR did not inform the RELIABILITY AUTHORITY of an IROL or SOL (for which actions are required for items 1 through 5) violation and the actions they are taking to return the system to within limits, or</p> <p>The Transmission Operator did not take corrective actions as directed by the RELIABILITY AUTHORITY to return the system to within the IROL within 30 minutes. (See table below)</p> <p>The limit violation was reported to the RELIABILITY COORDINATOR who did not provide appropriate direction to the Transmission Operator resulting in an IROL violation in excess of 30 minutes duration.</p>		

<b>Percentage by which IROL or SOL that has become an IROL is exceeded</b>	<b>Limit exceeded for more than 30 minutes, up to 35 minutes.</b>	<b>Limit exceeded for more than 35 minutes, up to 40 minutes.</b>	<b>Limit exceeded for more than 40 minutes, up to 45 minutes.</b>	<b>Limit exceeded for more than 45 minutes.</b>
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes)



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	009	Policy 2 — Transmission – Section B Voltage and Reactive Control	
Title	Voltage and Reactive Control		
Purpose	To ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time.	Policy 2B Requirement 1.	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. GENERATOR OPERATORS 5. PURCHASING SELLING ENTITIES		
Requirements	R1 Each TRANSMISSION OPERATOR and RELIABILITY AUTHORITY, individually and jointly, 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 and RELIABILITY AUTHORITIES.	Policy 2B Requirement 1.	
	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.	Policy 2B Requirement 2.	
	R3 Each PURCHASING-SELLING ENTITY shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by each BALANCING AUTHORITY and/or TRANSMISSION OPERATOR.	Policy 2B Requirement 2.1	
	R4 Each TRANSMISSION OPERATOR shall operate its capacitive and inductive reactive resources within its area to maintain system and INTERCONNECTION voltages within established limits.	Policy 2B Requirement 3.	
	R5 The TRANSMISSION OPERATOR, if necessary, shall take actions to	Policy 2B	This requirement may be

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	maintain voltage levels, including reactive generation scheduling, transmission line and reactive resource switching, etc., and load shedding.	Requirement 3.1	somewhat redundant with Requirement 4, unless this requirement can be clarified to refer to more urgent actions to avoid a critical voltage violation.
R6	<p>A TRANSMISSION OPERATOR shall maintain reactive resources to support its voltage under first contingency conditions.</p> <p>A TRANSMISSION OPERATOR shall disperse and locate reactive resources so that the resources can be applied effectively and quickly by the TRANSMISSION OPERATOR when contingencies occur.</p>	<p>Policy 2B Requirement 3.2</p> <p>Policy 2B Requirement 3.2.1</p>	
R7	TRANSMISSION OPERATORS shall correct IROL violations resulting from reactive resource deficiencies within 30 minutes and complete the required IROL violation reporting.	Policy 2B Requirement 3.2.2	
R8	<p>When a generator's voltage regulator is out of service, the GENERATION OPERATOR shall maintain the generator field excitation at a level to maintain INTERCONNECTION and generator stability.</p> <p>The 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.</p>	<p>Policy 2B Requirement 3.3</p> <p>Policy 2B Requirement 4.2</p>	
R9	The TRANSMISSION OPERATOR shall provide information on the status of all transmission reactive power resources, to its RELIABILITY AUTHORITY.	P2 B. 4.1	
R10	The TRANSMISSION OPERATOR and BALANCING AUTHORITY shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	Policy 2B Requirement 5.	
R11	The TRANSMISSION OPERATOR shall establish authority to direct the operation of devices necessary to regulate transmission voltage and reactive flow.	Policy 2B Requirement 6.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
Measures	Not Specified		
Regional Differences	None Identified		
Compliance Monitoring Process	Not Specified		
Levels of Non Compliance	Not Specified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	009	Policy 2 — Transmission – Section B Voltage and Reactive Control	
Title	Voltage and Reactive Control		
Purpose	To ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time.	Policy 2B Requirement 1.	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. GENERATOR OPERATORS 5. PURCHASING SELLING ENTITIES		
Requirements	R1 Each TRANSMISSION OPERATOR and RELIABILITY AUTHORITY, individually and jointly, 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 and RELIABILITY AUTHORITIES.	Policy 2B Requirement 1.	
	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.	Policy 2B Requirement 2.	
	R3 Each PURCHASING-SELLING ENTITY shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by each BALANCING AUTHORITY and/or TRANSMISSION OPERATOR.	Policy 2B Requirement 2.1	
	R4 Each TRANSMISSION OPERATOR shall operate its capacitive and inductive reactive resources within its area to maintain system and INTERCONNECTION voltages within established limits.	Policy 2B Requirement 3.	
	R5 The TRANSMISSION OPERATOR, if necessary, shall take actions to	Policy 2B	This requirement may be

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	maintain voltage levels, including reactive generation scheduling, transmission line and reactive resource switching, etc., and load shedding.	Requirement 3.1	somewhat redundant with Requirement 4, unless this requirement can be clarified to refer to more urgent actions to avoid a critical voltage violation.
R6	<p>A TRANSMISSION OPERATOR shall maintain reactive resources to support its voltage under first contingency conditions.</p> <p>A TRANSMISSION OPERATOR shall disperse and locate reactive resources so that the resources can be applied effectively and quickly by the TRANSMISSION OPERATOR when contingencies occur.</p>	<p>Policy 2B Requirement 3.2</p> <p>Policy 2B Requirement 3.2.1</p>	
R7	TRANSMISSION OPERATORS shall correct IROL violations resulting from reactive resource deficiencies within 30 minutes and complete the required IROL violation reporting.	Policy 2B Requirement 3.2.2	
R8	<p>When a generator's voltage regulator is out of service, the GENERATION OPERATOR shall maintain the generator field excitation at a level to maintain INTERCONNECTION and generator stability.</p> <p>The 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.</p>	<p>Policy 2B Requirement 3.3</p> <p>Policy 2B Requirement 4.2</p>	
R9	The TRANSMISSION OPERATOR shall provide information on the status of all transmission reactive power resources, to its RELIABILITY AUTHORITY.	P2 B. 4.1	
R10	The TRANSMISSION OPERATOR and BALANCING AUTHORITY shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	Policy 2B Requirement 5.	
R11	The TRANSMISSION OPERATOR shall establish authority to direct the operation of devices necessary to regulate transmission voltage and reactive flow.	Policy 2B Requirement 6.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
Measures	Not Specified		
Regional Differences	None Identified		
Compliance Monitoring Process	Not Specified		
Levels of Non Compliance	Not Specified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	010	Policy 3 – Interchange Version 5.2 Policy Subsections A. Interchange Transaction Implementation  P3T3 Template	
Title	Interchange Transaction Tagging		Tagging Transactions
Purpose	To ensure that Interchange Transactions, certain Interchange Schedules, and certain intra-Balancing Area transfers using point-to-point transmission service are tagged in adequate time to allow them to be assessed for reliability impacts before being approved by the affected RELIABILITY AUTHORITIES, TRANSMISSION SERVICE PROVIDERS and BALANCING AUTHORITIES, and to allow adequate time for implementation.		
Effective Date	February 8, 2005		
Applicability	1. PURCHASE-SELLING ENTITIES 2. BALANCING AUTHORITIES		
Requirements	<p>R1 The load-serving PURCHASING-SELLING ENTITY shall be responsible for tagging all INTERCHANGE TRANSACTIONS (those that are between BALANCING AUTHORITY AREAS) and all transfers that are entirely within a BALANCING AREA using point-to-point transmission service (including all grandfathered and “non-Order 888” point-to-point transmission service). The load-serving PURCHASING-SELLING ENTITY shall be responsible for tagging all DYNAMIC SCHEDULES at the expected average MW profile for each hour.</p> <p>R2 The sink BALANCING AUTHORITY shall be responsible for tagging all INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, and all emergency transactions to mitigate SOL or IROL violations. Such interchange shall be exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins, regardless of magnitude or duration.</p>	<p>Policy 3A Requirement 2.1 Compliance Template P3T3</p> <p>Policy 3A Requirement 2.4.1</p>	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>R3 The sink BALANCING AUTHORITY shall be responsible for tagging all Bilateral Inadvertent Interchange Payback.</p> <p>R4 The BALANCING AUTHORITY or PURCHASING SELLING ENTITY responsible for submitting the tag shall submit all tags to the SINK BALANCING AUTHORITY according to timing tables in Attachment 1.</p>	<p>Policy 3A Requirement 2.4.1</p> <p>Policy 3A Requirement 2.4 Appendix 3A1</p>	This requirement is not intended to include unilateral payback, if it is recognized by policy.
Measures	A BALANCING AUTHORITY shall meet 100% of the tagging requirements for all scheduled interchange between BALANCING AUTHORITY AREAS and within the BALANCING AREA.	Compliance Template P3T3	
Regional Differences	<p>WECC Waiver:</p> <ul style="list-style-type: none"> <li>o Inadvertent Payback</li> <li>o Dynamic Schedules</li> </ul>	Approved waiver.	
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

## Attachment 1 – Tag Submission and Response Timetables for New Transactions

### A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for 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 than 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” by the E-Tag system and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties. The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule TRANSACTIONS without the proper tag (Policy 3, Section A 6.1).

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 with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags with a duration of 24 hours or more must be evaluated in two hours.

#### ***Timing Requirements for Reallocation when in a 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 by the Interchange Distribution Calculator no later than 35 minutes prior to the top of the hour to allow time for RELIABILITY AUTHORITY to assess the impact of reallocation.

## **B. Western Interconnection – New Transactions**

The table below represents the recommended business practices for 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	Late Status	Actual Tag	Provider	Approval/Denial	Time to Start of
-------------	-------------	------------	----------	-----------------	------------------

Start/Submittal Time	Deadline	Submission Time*	Assessment Time	Notes	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:**

1. All clock times are in PPT.
2. Tags falling under the criteria in yellow are deemed pre-schedule tags.
3. Tags falling under the criteria in green are deemed real-time tags.
4. Pre-schedule tags submitted between 15:00 and 18:00 will be assigned LATE composite status.
5. 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 than 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” by the E-Tag system and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties.

The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule TRANSACTIONS without the proper tag (Policy 3, Section A 6.1).

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 with a duration of 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.



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<ul style="list-style-type: none"> <li>• OASIS reservation accommodates multiple INTERCHANGE TRANSACTIONS</li> <li>• Connectivity of adjacent TRANSMISSION SERVICE PROVIDERS.</li> <li>• Loss accounting</li> </ul> <p>R3 BALANCING AUTHORITIES on the SCHEDULING PATH shall be responsible for assessing and approving or denying the INTERCHANGE TRANSACTION. The BALANCING AUTHORITY shall verify and assess:</p> <ul style="list-style-type: none"> <li>• Transaction start and end time</li> <li>• Energy profile, including the ramp (ability of the generation to support the magnitude and maneuverability of the transaction)</li> <li>• Scheduling path (proper connectivity of adjacent BALANCING AUTHORITIES)</li> </ul> <p>R5 Each BALANCING AUTHORITY and TRANSMISSION SERVICE PROVIDER on the scheduling path shall communicate their approval or denial of the INTERCHANGE TRANSACTION to the SINK BALANCING AUTHORITY.</p> <p>R6 Upon receipt of approvals or denials from all of the individual BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS, the SINK BALANCING AUTHORITY shall communicate the composite approval status of the INTERCHANGE TRANSACTION to the PURCHASING-SELLING ENTITY and all other BALANCING AUTHORITIES, TRANSMISSION SERVICE PROVIDERS and RELIABILITY AUTHORITIES on the scheduling path.</p>	<p>Policy 3A Requirement 4</p> <p>Policy 3A Requirement 5</p> <p>Policy 3A Requirement 5 and Policy 3B Requirement 3</p>	
Measures	Not Specified.		
Regional Differences	MISO Waiver: <ul style="list-style-type: none"> <li>○ Scheduling Agent Waiver</li> <li>○ Enhanced Scheduling Waiver</li> </ul>	Reference existing approved waivers.	
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	012	Policy 3 Interchange Section B Interchange Schedule Implementation  P3T3 Template	
Title	Interchange Transaction Implementation		
Purpose	To ensure BALANCING AUTHORITIES confirm INTERCHANGE SCHEDULES with adjacent BALANCING AUTHORITIES prior to implementing the schedules in their ACE equations. To ensure BALANCING AUTHORITIES incorporate all confirmed schedules into their AGC ACE equations.		
Effective Date	February 8, 2005		
Applicability	1. Balancing Authorities		
Requirements	<p>R1 Each RECEIVING BALANCING AUTHORITY shall confirm INTERCHANGE SCHEDULES with the SENDING BALANCING AUTHORITY prior to implementation in the BALANCING AUTHORITY's AREA CONTROL ERROR (ACE) equation or in the system that calculates the BALANCING AUTHORITY's AREA CONTROL ERROR equation. The SENDING BALANCING AUTHORITY and RECEIVING BALANCING AUTHORITY shall agree on:</p> <ul style="list-style-type: none"> <li>• Interchange Schedule start and end time</li> <li>• Energy profile, including ramp start time and rate <ul style="list-style-type: none"> <li>(a) Default ramp rate for the Eastern Interconnection shall be 10 minutes equally across the Interchange Schedule start and end times.</li> <li>(b) Default ramp rate for the Western Interconnection shall be 20 minutes equally across the Interchange Schedule start and end times.</li> <li>(c) 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</li> </ul> </li> </ul>	<p>Policy 3B Requirement 4</p> <p>Policy 3B Requirement 4.1</p>	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>Authority and Receiving Balancing Authority.</p> <ul style="list-style-type: none"> <li>If a DC tie is on the contract path, then the SENDING BALANCING AUTHORITIES and RECEIVING BALANCING AUTHORITIES shall coordinate the INTERCHANGE SCHEDULE with the TRANSMISSION OPERATOR of the DC tie.</li> </ul> <p>R2 BALANCING AUTHORITIES shall implement INTERCHANGE SCHEDULES only with ADJACENT BALANCING AUTHORITIES.</p> <p>R3 The SINK BALANCING AUTHORITY shall be responsible for initiating implementation of each INTERCHANGE TRANSACTION as tagged. Each BALANCING AUTHORITY on the scheduling path shall incorporate each INTERCHANGE TRANSACTION into its INTERCHANGE SCHEDULES.</p>	<p>Policy 3 C Requirement 3.4</p> <p>Policy 3B Requirement 4.1.3</p> <p>Policy 3B Requirement1.</p>	
Measures	Not Specified.		
Regional Differences	<p>MISO Waivers:</p> <ul style="list-style-type: none"> <li>Scheduling Agent Waiver</li> <li>Enhanced Scheduling Waiver</li> <li>Energy Flow Information Waiver</li> </ul>		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	013	Policy 3 – Interchange Section D – Interchange Transaction Modifications  Compliance Template P3T3	
Title	Interchange Transaction Modifications		
Purpose	To allow modifications to an Interchange Transaction.		
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES 2. TRANSMISSION SERVICE PROVIDERS 3. RELIABILITY AUTHORITIES 4. PURCHASING-SELLING ENTITIES		
	<p>R1 Any RELIABILITY AUTHORITY, TRANSMISSION SERVICE PROVIDER, SOURCE BALANCING AUTHORITY, or SINK BALANCING AUTHORITY that requires modification to an INTERCHANGE TRANSACTION due to loss of generation, loss of load, or a TLR event (or other regional congestion management practices) shall set a new limit on the INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started, and shall communicate this new limit to the SINK BALANCING AUTHORITY. 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.</p> <p>R2 The SINK BALANCING AUTHORITY shall be responsible for implementing the required modifications to the INTERCHANGE TRANSACTIONS tag to comply with the specified new limit set in Requirement 1.</p> <p>R3 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.</p>	Policy 3D	<p>Policy #3, Section D</p> <p>This requirement assumes that if a limit is released, the requesting entity would be required to go through the tag request process to reload the transaction.</p>



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>R4 A PURCHASING-SELLING ENTITY responsible for tagging a DYNAMIC INTERCHANGE SCHEDULE shall modify the tag when the energy profile deviates by more than 25% from the previously tagged energy profile.</p> <p>R5 A BALANCING AUTHORITY or PURCHASING-SELLING ENTITY wishing to modify an INTERCHANGE TRANSACTION shall submit a request to modify the tag to the Sink Balancing Authority according to the timing tables in Attachment 1.</p>	Policy 3A Requirement 2.1	<p>The Drafting Team believes that a straight 25% deviation threshold is not useful for reliability. Small transactions varying a fraction of a MW could be required to submit a new tag while a 1,000 MW transaction with a 249 MW deviation would not. The Drafting Team is requesting comment on a proposed improvement to this requirement. The proposed language is:</p> <p>A Purchasing-Selling Entity responsible for tagging a DYNAMIC INTERCHANGE SCHEDULE shall modify the tag when the energy profile deviates from the previously tagged profile as follows:</p> <ul style="list-style-type: none"> <li>○ The transaction is 100 MW or less and the deviation is more than 10 MW; or</li> <li>○ The transaction is greater than 100 MW and the deviation is greater than 25% (or 10%)</li> </ul> <p>The Drafting Team is asking commenters whether they agree with the modified structure of the requirement and the appropriate numerical cutoffs and percentages.</p>
Measures	Not Specified.		
Regional	WECC Waiver:		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Differences	○ Tagging Dynamic Schedules and Inadvertent Payback		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

## Attachment 1

### Interchange Transaction Corrections

---

TRANSACTION Corrections may be provided by PSE submitting the Tag to replace non-reliability data listed in a tag. As each correction is received, the Evaluation Time of the TRANSACTION will extend, based on the following rules:

- Each correction shall extend the evaluation time by ten minutes
- At no time can the evaluation time be extended past the start time of the TRANSACTION.
- Each correction shall reset the approval status of those entities affected by the correction
- The segment or segments corrected will be eligible for passive approval if the correction is received within the timelines specified below, except in the case where the TRANSACTION has already been set for passive denial. The segment or segments corrected will be subject to passive denial if the correction is not received within the timelines specified below. At no point may a TRANSACTION segment already under Passive Denial constraints be returned to Passive Approval eligibility.

**Table 1: Correction Submission Requirements\***

Eastern Interconnection	Western Interconnection
20 minutes prior to start	30 minutes prior to start
*Start time references are for start of the Transaction not the start of the ramp.	

### 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 2: 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 3: Western Interconnection – Modifications**

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market – Committed Transmission Reservation(s) Reductions	N/A	N/A	N/A

Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Transaction not the start of the ramp.			

\*See Special Exception for Cancellations below

\*\*If received after deadline, requires active approval or will be passively denied

### Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the TRANSACTION **prior** to the start of a TRANSACTION but **following** that TRANSACTIONS approval. In the event that a PSE submitting the tag elects to cancel a TRANSACTION, the following timelines should be utilized:

**Table 4: 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.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	014	Policy 4 — System Coordination Policy Section A — Monitoring System Conditions	This standard is one of several that have potential redundancy with other standards. The Drafting Team is seeking industry comment on the extent to which redundancies should be eliminated in Version 0.
Title	Monitoring System Conditions		
Purpose	To ensure critical reliability parameters are monitored in real-time.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. GENERATOR OPERATORS		
Requirements	R1 GENERATOR OPERATORS shall inform the HOST BALANCING AUTHORITY and the TRANSMISSION OPERATOR of all generation resources available for use. TRANSMISSION OPERATORS and BALANCING AUTHORITIES shall inform the RELIABILITY AUTHORITY and other affected BALANCING AUTHORITIES and TRANSMISSION OPERATORS of all generation and transmission resources available for use.	Policy 4A Requirement 1.	Translating to active voice and the Functional Model forces the question of hierarchy or reporting reliability information that is implied in the Functional Model. The Drafting Team has made one interpretation here and recognizes the need for further work and industry input. One approach would be to have the standard apply only to Bas and TOs and assume that Generator Operator and other functions are obligated through service agreements or connection requirements.
	R2 RELIABILITY AUTHORITIES, BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall monitor applicable transmission line status, MW and MVAR flows, voltage, LTC settings and status of rotating and static reactive resources.	Policy 4A Requirement 2.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
	R3 Each RELIABILITY AUTHORITY, BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall provide appropriate technical information concerning protective relays to operating personnel.	Policy 4A Requirement 3.	
	R4 The RELIABILITY AUTHORITY, BALANCING AUTHORITY and TRANSMISSION OPERATOR shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	Policy 4A Requirement 4.	Is load forecasting required for reliability or not, if not, why is this information required?
	R5 Each RELIABILITY AUTHORITY, BALANCING AUTHORITY and TRANSMISSION OPERATOR shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	Policy 4A Requirement 5.	
	R6 Each BALANCING AUTHORITY and TRANSMISSION OPERATOR shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Policy 4A Requirement 5.1	
	R7 RELIABILITY AUTHORITIES, BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall monitor system frequency.	Policy 4A Requirement 6.	
Measures	Not Specified		
Regional Differences	None Identified		
Compliance Monitoring Process	Not Specified		
Levels of Non Compliance	Not Specified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	015	Compliance Template P4T2  Policy 4 Section B	
Title	Operational Reliability Information		
Purpose	To provide the Reliability Authority with operating data that the Reliability Authority requires to monitor system conditions within the Reliability Authority Area.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITY 2. TRANSMISSION OPERATORS 3. BALANCING AUTHORITIES 4. PURCHASING SELLING ENTITIES		
Requirements	R1 Each BALANCING AUTHORITY and TRANSMISSION OPERATOR shall provide its RELIABILITY AUTHORITY with operating data that the RELIABILITY AUTHORITY requires for monitoring system conditions within the RELIABILITY AUTHORITY AREA. The RELIABILITY AUTHORITY shall identify the data requirements from the list in Attachment 1. The RELIABILITY AUTHORITY shall identify any additional operating information requirements, relating to operation of the bulk power system, and which data must be provided electronically.		
	R2 As a condition of receiving data from the Interregional Security Network (ISN), all ISN data recipients shall sign the NERC Confidentiality Agreement for Electric System Security Data.	Policy 4B Requirement 2.  Policy 4B Requirement 1.	The Drafting Team has clarified the following requirement in the current policy: The Electric System Security Data referred to in this Policy and received over the Interregional Security Network shall be used only for operational security analysis and shall not be made available to nor used by Purchasing-Selling Entities in the wholesale merchant function.
	R3 Upon request, RELIABILITY AUTHORITIES shall, via the ISN, exchange with each other operating data that is necessary to allow the RELIABILITY AUTHORITIES to perform their	Policy 4B Requirement 4.	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	operational reliability assessments and coordinate their reliable operations. RELIABILITY AUTHORITIES shall share with each other the types of data as listed in Attachment 1, unless otherwise agreed to.	Policy 4B Requirement 4.1	
	R4 Upon request, EACH BALANCING AUTHORITY and TRANSMISSION OPERATOR shall provide to other BALANCING AUTHORITIES and TRANSMISSION OPERATORS with immediate responsibility for operational reliability, the operating data that are necessary to allow the BALANCING AUTHORITY and TRANSMISSION OPERATOR to perform its operational reliability assessment and to coordinate reliable operations. BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall provide the types of data as listed in Addendum A, unless otherwise agreed to by the BALANCING AUTHORITIES and TRANSMISSION OPERATORS with immediate responsibility for operational security.	Policy 4B Requirement 5.  Policy 4B Requirement 5.1	
	R5 PURCHASING-SELLING ENTITIES shall provide information as requested by their host BALANCING AUTHORITIES and TRANSMISSION OPERATORS to enable them to conduct operational reliability assessments and coordinate reliable operations.	Policy 4B Requirement 6.	
Measures	Evidence that the RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR, and PURCHASING-SELLING ENTITY is providing the information required, within the time intervals specified therein, and in a format agreed upon by the requesting RELIABILITY AUTHORITY.		
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review Entities will be selected for operational reviews at least every three years.</p> <p>Entities shall annually self-certify compliance to the measures as required by its RRC.</p> <p>Exception Reporting Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>	Compliance Template P4T2	Proposed to remove the compliance monitoring section from the Version 0 standards.



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	Reset Period One Calendar year without a violation from the time of the violation		
Levels of Non Compliance	Level 1 — The Operating Authority is providing the Reliability Coordinator with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect). Level 2 — N/A Level 3 — N/A Level 4 — The Operating Authority is not providing the Reliability Coordinator with data having the specified content, or time interval reporting, or format. The information missing is included in the RC's list of data.		

## Attachment 1 – Electric System Security Data

This Attachment lists the types of data that BALANCING AUTHORITIES, RELIABILITY AUTHORITIES AND TRANSMISSION OPERATORS are expected to provide, and are expected to share with each other as explained on Policy 4B, “System Coordination – Operational Security Information.”

1. **Information updated at least every ten minutes.** The following information to be updated at least every ten minutes:
  - 1.1. **Transmission data.** Transmission data for all INTERCONNECTIONS plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1. Status
    - 1.1.2. MW or ampere loadings
    - 1.1.3. MVA capability
    - 1.1.4. Transformer tap and phase angle settings
    - 1.1.5. Key voltages
  - 1.2. **Generator data.**
    - 1.2.1. Status

- 1.2.2. MW and MVAR capability
- 1.2.3. MW and MVAR net output
- 1.2.4. Status of automatic voltage control facilities

**1.3. Operating reserve**

- 1.3.1. MW reserve available within ten minutes

**1.4. BALANCING AUTHORITY Demand**

- 1.4.1. Instantaneous

**1.5. Interchange**

- 1.5.1. Instantaneous actual interchange with each BALANCING AUTHORITY.
- 1.5.2. Current INTERCHANGE SCHEDULES with each BALANCING AUTHORITY by individual INTERCHANGE TRANSACTION, including INTERCHANGE identifiers, and reserve responsibilities.
- 1.5.3. INTERCHANGE SCHEDULES for the next 24 hours

**1.6. Area Control Error and Frequency**

- 1.6.1. Instantaneous area control error
- 1.6.2. Clock hour area control error
- 1.6.3. System frequency at one or more locations in the BALANCING AUTHORITY

**2. Other operating information updated as soon as available**

- 2.1. INTERCONNECTION RELIABILITY OPERATING LIMITS AND SYSTEM OPERATING LIMITS in effect.
- 2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.
- 2.3. Forecast peak demand for current day and next day.
- 2.4. Forecast changes in equipment status
- 2.5. New facilities in place
- 2.6. New or degraded special protection systems

2.7. Emergency operating procedures in effect

2.8. Severe weather, fire, or earthquake

2.9. Multi-site sabotage

3. **Data retention.** There are no requirements on any RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or Region to retain the data that they make available on the Interregional Security Network. Therefore, if the recipient of the data wishes to access historical data, it shall establish a method for saving the data it obtains from the Network.

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	016	Compliance Template P4T4  Policy 4 Section C	
Title	Planned Outage Coordination		
Purpose	Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among BALANCING AUTHORITIES, TRANSMISSION OPERATORS, AND RELIABILITY AUTHORITIES.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. Generator Operators</li> <li>2. Transmission Operators</li> <li>3. Balancing Authorities</li> <li>4. Reliability Authorities</li> </ol>		This standard provides another example of the question whether Generator Operators are intended to be part of “Operating Authorities” or should their obligations be addressed through service agreements?
Requirements	<p>R1 GENERATOR OPERATORS and TRANSMISSION OPERATORS shall provide outage information daily, by noon prevailing time of the their RELIABILITY AUTHORITY, for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation, to their RELIABILITY AUTHORITY, or to neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS. The RELIABILITY AUTHORITY shall establish the outage reporting requirements.</p>	Compliance Template P4T4	Drafting Team assumes the time requirement is based on noon prevailing time of the RELIABILITY AUTHORITY, although it is not clear from Policy 4. Policy 9 states specific times for the Eastern and Western Interconnections. The Drafting Team recommends using the Policy 9 time requirements.
	<p>R2 RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, BALANCING AUTHORITIES, AND GENERATOR OPERATORS shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS as required.</p>	Policy 4C Requirement 1.	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	R3 RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, BALANCING AUTHORITIES, and GENERATOR OPERATORS shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Policy 4C Requirement 3.	
	R4 The RELIABILITY AUTHORITY shall resolve any scheduling of potential reliability conflicts.	Compliance Template P4T4	
Measures	Monitored entity shall report and coordinate scheduled generator and/or bulk transmission outages to its RELIABILITY AUTHORITY and others indicated in the requirements above.	Compliance Template P4T4	
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review: The Regional Reliability Councils shall conduct a review every three years to ensure that each Operating Authority has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Control Areas.</p> <p>Investigation: At the discretion of the RRC or NERC, an investigation may be initiated to review the planned outage process of monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the RRC to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the RRC.</p> <p>A RELIABILITY AUTHORITY makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The RELIABILITY AUTHORITY must provide all its documentation within 3 business days to the region. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p> <p>Reset Period: One Calendar year without a violation from the time of the violation</p> <p>Supporting Notes:</p>	Compliance Template P4T4	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>The operating records of the responsible entity for a period of at least one month, (from a three month rolling window), shall be inspected in the field audit to verify that scheduled generator and transmission outages have been planned and coordinated among affected entities. These records are subject to correlation and confirmation with adjacent entities.</p> <p>Each neighboring responsible entity shall develop and share a list of critical facilities that it will receive notification of future and actual outages.</p>		
Levels of Non Compliance	<p>Level 1 — The responsible entity has a process in place to provide information to their RELIABILITY AUTHORITY but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring BALANCING AREAS.</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — There is no process in place to exchange outage information, or the responsible entity does not follow the directives of the RELIABILITY AUTHORITY to cancel or reschedule an outage.</p>	Compliance Template P4T4	

Draft Version 0 Standard		Policy Reference	
Standard	017	Policy 4 — System Coordination Section B. System Protection Coordination	
Title	System Protection Coordination		
Purpose	To ensure system protection is coordinated.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. GENERATOR OPERATORS		
Requirements	R1 RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, BALANCING AUTHORITIES, and GENERATOR OPERATORS shall be familiar with the purpose and limitations of protection system schemes applied in their area.	Policy 4D Requirement 1.	
	R2 If a protective relay or equipment failure reduces system reliability, the TRANSMISSION OPERATOR or GENERATOR OPERATOR shall notify the affected RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES, and shall take corrective action as soon as possible.	Policy 4D Requirement 2	
	R3 TRANSMISSION OPERATORS and GENERATOR OPERATORS shall coordinate all new protective systems and all protective system changes with affected RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES.	Policy 4D Requirement 3.	
	R4 TRANSMISSION OPERATORS shall coordinate protection systems on major transmission lines and interconnections with affected GENERATOR OPERATORS, RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES.	Policy 4D Requirement 4.	
	R5 Each TRANSMISSION OPERATOR and GENERATOR OPERATOR shall notify its RELIABILITY AUTHORITY and neighboring TRANSMISSION OPERATORS and BALANCING AUTHORITIES in advance of changes in generating sources, transmission, load, or operating conditions, which could require changes in their protection systems.	Policy 4D Requirement 5.	Additional work is required to clarify the reporting hierarchy. The Drafting Team does not believe the Generator Operator would report directly to the Reliability Authority, but would report through the Transmission Operator or Balancing Authority. This hierarchy question affects a number of

Draft Version 0 Standard		Policy Reference	
			requirements in several standards.
	R6 Each TRANSMISSION OPERATOR and BALANCING AUTHORITY shall monitor the status of each SPECIAL PROTECTION SYSTEM in their area, and shall notify all affected RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES of each change in status.	Policy 4D Requirement 5.1	
Measures	Not Specified.		
Regional Differences	Not Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	018	Operating Policy 5 Section A	
Title	Reliability Responsibilities and Authorities		
Purpose	The integrity and reliability of the BULK ELECTRIC SYSTEM shall take precedence above all other aspects including commercial operations; therefore, all reliability entities are required to cooperate and take appropriate action to mitigate the severity or extent of any system emergency. The focus of policy 5 is on recognizing and responding to emergencies.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. RELIABILITY AUTHORITIES</li> <li>2. BALANCING AUTHORITIES</li> <li>3. TRANSMISSION OPERATORS</li> <li>4. GENERATOR OPERATORS</li> <li>5. DISTRIBUTION PROVIDERS</li> <li>6. LOAD SERVING ENTITIES</li> </ol>		This standard is a clear example of the question of intent of the operating policies – do the requirements address generator, distribution provider, and LSE requirements, or are those addressed through service agreements for the purpose of Version 0 standards?
Requirements	R1 The RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate operating emergencies.	Policy 5A Requirement 2	
	R2 The RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.		
	R3 The BALANCING AUTHORITY, TRANSMISSION OPERATOR, AND GENERATOR OPERATOR shall comply with RELIABILITY AUTHORITY directives, and the GENERATOR OPERATOR shall comply with TRANSMISSION OPERATOR reliability directives, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the BALANCING AUTHORITY, TRANSMISSION OPERATOR , OR GENERATOR OPERATOR shall immediately inform the RELIABILITY AUTHORITY, or TRANSMISSION OPERATOR, of the inability to perform the directive	Policy 5A Requirement 2.2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>so that the RELIABILITY AUTHORITY or TRANSMISSION OPERATOR can implement alternate remedial actions.</p> <p>The DISTRIBUTION PROVIDER and LOAD SERVING ENTITY shall comply with all reliability directives issued by the TRANSMISSION OPERATOR, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the DISTRIBUTION PROVIDER or LOAD SERVING ENTITY shall immediately inform the TRANSMISSION OPERATOR of the inability to perform the directive so that the TRANSMISSION OPERATOR can implement alternate remedial actions.</p>	Policy 5A Requirement 2.2.1	Note the reason for separating this item is to highlight the inclusion of DP and LSE in the interpretation of Operating Authorities for the purpose of directing emergency actions.
	R4 The RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall inform other potentially affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS of real time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency.	Policy 5A Requirement 4	
	<p>R5 The RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall render all available emergency assistance requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.</p> <p>The DISTRIBUTION PROVIDER and LOAD SERVING ENTITY shall assist the requesting entity, unless such actions would violate safety, equipment, regulatory or statutory requirements.</p>	<p>Policy 5A Requirement 5</p> <p>Policy 5A Requirement 5.1</p>	
	<p>R6 The TRANSMISSION OPERATOR AND GENERATOR OPERATOR shall not remove BULK ELECTRIC SYSTEM facilities from service if removing those facilities would BURDEN neighboring systems unless:</p> <ul style="list-style-type: none"> <li>For a generator, the GENERATOR OPERATOR first notifies and coordinates with the BALANCING AUTHORITY. The BALANCING AUTHORITY shall notify the Reliability Authority, Transmission Operator, and affected Balancing Authorities, and coordinate the impact resulting from the removal of the BULK ELECTRIC SYSTEM facility.</li> <li>For a transmission facility, the TRANSMISSION OPERATOR first notifies and coordinates with the RELIABILITY AUTHORITY and</li> </ul>	<p>Policy 5A Requirement 6</p> <p>Policy 5A Requirement 6.1</p> <p>Policy 5A Requirement 6.2</p>	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>the TRANSMISSION OPERATOR notifies other affected TRANSMISSION OPERATORS and coordinates the impact resulting from the removal of the BULK ELECTRIC SYSTEM facility.</p> <ul style="list-style-type: none"> <li>When time does not permit such notification and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the RELIABILITY AUTHORITY or TRANSMISSION OPERATOR shall notify adjacent RELIABILITY AUTHORITIES at the earliest possible time to ensure coordination.</li> </ul>		
	R7 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall immediately take action to restore the real and reactive power balance. If the BALANCING AUTHORITY or TRANSMISSION OPERATOR is unable to restore its real and reactive power balance it shall request emergency assistance from the RELIABILITY AUTHORITY. If corrective action or emergency assistance is not adequate to mitigate the real and reactive power balance, then the RELIABILITY AUTHORITY, BALANCING AUTHORITY and TRANSMISSION OPERATOR shall implement firm load shedding.	Policy 5A Requirement 11	
Measures	Not Specified		
Regional Differences	None Identified		
Compliance Monitoring Process	Not Specified		
Levels of Non Compliance	Not Specified		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	019	Operating Policy 5B	
Title	Communications and Coordination		
Purpose	To ensure RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, TRANSMISSION OPERATORS, and GENERATOR OPERATORS have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. GENERATOR OPERATORS		
Requirements	R1 The BALANCING AUTHORITY, TRANSMISSION OPERATOR, and GENERATOR OPERATOR shall have communications (voice and data links) with appropriate RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS. Such communications shall be staffed and available for addressing a real-time emergency condition.	Policy 5B	This is another example of the question whether the operating policy intends under Operating Authority to require a Generator Operator to have communications equipment?  This requirement is related to Operating Policy 7A.
	R2 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall notify its RELIABILITY AUTHORITY and all other potentially affected BALANCING AUTHORITIES and TRANSMISSION OPERATORS through predetermined communication paths of any condition that could threaten the reliability of its area.	Policy 5B	
	R4 - The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.	Policy 5B	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Compliance			

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	O20		
Title	Emergency Operations/Implementation of Capacity and Energy Emergency plans and coordination with other systems	Operating Policy 5 Section C	
Purpose	To ensure Balancing Authorities and Transmission Operators are prepared for capacity and energy emergencies.		This standard is closely related to the energy emergency standards in Operating Policy 9. Policy 5 is focused on Operating Authorities and Policy 9 addresses Reliability Coordinator requirements. The Drafting Team believes there is an opportunity for consolidation of these requirements in Version 0.
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES 2. TRANSMISSION OPERATORS		
Requirements	R1 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall implement their Capacity and Energy Emergency plans, when required and as appropriate, to reduce risks to the interconnected system.	Compliance Template P5T1	
	R2 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall communicate their current and future system conditions to neighboring BALANCING AUTHORITY and TRANSMISSION OPERATORS and their RELIABILITY COORDINATOR if they are experiencing an operating emergency.	Compliance Template P5T1	
	R3 A deficient BALANCING AUTHORITY shall only use the assistance provided by the INTERCONNECTION's frequency bias for the time needed to implement corrective actions. If the BALANCING AUTHORITY cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: <ul style="list-style-type: none"> <li>• Requesting assistance from other BALANCING AUTHORITIES;</li> <li>• Declaring an Energy Emergency through its RELIABILITY AUTHORITY; and</li> <li>• Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm</li> </ul>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	loads.		
	R4 A BALANCING AUTHORITY anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.		
	<p>R5 Once the BALANCING AUTHORITY has exhausted the following steps:</p> <ul style="list-style-type: none"> <li>• All available generating capacity is loaded; and</li> <li>• All operating reserve is utilized; and</li> <li>• All interruptible load and interruptible exports have been interrupted; and</li> <li>• All emergency assistance from other BALANCING AUTHORITIES is fully utilized; and</li> <li>• Its ACE is negative and cannot be returned to zero in the next fifteen minutes;</li> </ul> <p>Then the deficient BALANCING AUTHORITY shall:</p> <ul style="list-style-type: none"> <li>• Manually shed firm load without delay to return its' ACE to zero; and</li> <li>• The deficient BALANCING AUTHORITY shall request the Reliability Authority to declare an Emergency Energy Alert in accordance with Attach 5C (was 9B).</li> </ul>		
Requirements	R6 The RELIABILITY AUTHORITY that is experiencing a potential or actual Energy Emergency within any BALANCING AUTHORITY Area within its RELIABILITY AUTHORITY AREA shall initiate an Energy Emergency Alert as detailed in Attachment 1 “Energy Emergency Alert Levels.” The RELIABILITY AUTHORITY shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Policy 9F Requirement 7. Compliance Template P5T1	
Measures	M1 At the discretion of the Regional Reliability Council or NERC, an investigation may be initiated to review the operation of a Balancing Authority or Transmission Operator when they have implemented their Capacity and Energy Emergency plans. Notification of an investigation must be made by the Regional Reliability Council to the BALANCING AUTHORITY OR TRANSMISSION OPERATOR being investigated as soon as possible, but no later than 60 days after the event. The BALANCING AUTHORITY and TRANSMISSION OPERATOR will be reviewed to	Compliance Template P5T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>determine if their Capacity and Energy Emergency Plans were appropriately (for a particular situation, not all of the steps may be effective or required) followed.</p> <p>M2 Evidence will be gathered to determine the level of communication between the BALANCING AUTHORITY and TRANSMISSION OPERATOR and other BALANCING AUTHORITIES and TRANSMISSION OPERATORS. An assessment will be made by the investigator(s) as to whether the level and timing of communication of system conditions and actions taken to relieve emergency conditions was acceptable and in conformance with the Capacity and Energy Emergency Plans.</p> <p>Reset period: One Calendar year without a violation from the time of the violation.</p> <p>Data Retention: The Balancing Authority and Transmission Operator is required to maintain operational data, logs and voice recordings relevant to the implementation of the Capacity and Energy Emergency Plans for 60 days following the implementation. After an investigation is completed, the Regional Reliability Council is required to keep the report of the investigation on file for two years.</p>		
Regional Differences	Not Identified.		
Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition.</p> <p>Level 4 — One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition and there was a delay or gap in communications.</p>		



## Attachment 1 Energy Emergency Alerts

### Introduction

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

The Energy Emergency Alert Procedure is initiated by the LSE's RELIABILITY AUTHORITY, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels" to provide assistance to the LSE.

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

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

#### A. General Requirements

---

- 1. Initiated only by Reliability Authority.** An Energy Emergency Alert may be initiated only by a RELIABILITY AUTHORITY at 1) the RELIABILITY COORDINATOR'S own request, or 2) upon the request of a BALANCING AUTHORITY, or 3) upon the request of a LOAD SERVING ENTITY. The cost of available resources shall not be a consideration for initiating an alert.

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

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

This will go into the NEASB document

- 2. Notification.** A RELIABILITY AUTHORITY who declares an Energy Emergency Alert shall notify all BALANCING AUTHORIZES and TRANSMISSION PROVIDERS in his RELIABILITY AREA. The RELIABILITY AUTHORITY shall also notify all other RELIABILITY AUTHORITIES of the situation via the Reliability Authority Information System (RCIS). Additionally, conference calls between RELIABILITY AUTHORITIES shall be held as necessary to communicate system conditions. The RELIABILITY AUTHORITY shall also notify the other RELIABILITY AUTHORITIES when the Alert has ended.

### 2. B. Energy Emergency Alert Levels

---

#### Introduction

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

The RELIABILITY AUTHORITY may declare whatever Alert level is necessary, and need not proceed through the alerts sequentially.

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

**Circumstances:**

- BALANCING AUTHORITY, RESERVE SHARING GROUP, or LOAD SERVING ENTITY foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required OPERATING RESERVES, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed

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

**Circumstances:**

- BALANCING AUTHORITY, RESERVE SHARING GROUP, or LOAD SERVING ENTITY is no longer able to provide its customers' expected energy requirements, and is designated an ENERGY DEFICIENT ENTITY.
- ENERGY DEFICIENT ENTITY foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand
  - Voltage reduction
  - Interruption of non-firm end use loads in accordance with applicable contracts<sup>1</sup>
  - Demand-side management
  - Utility load conservation measures

During Alert 2, RELIABILITY AUTHORITIES, BALANCING AUTHORITY, and ENERGY DEFICIENT ENTITIES have the following responsibilities:

- 2.1 Notifying other Balancing Authorities and Market Participants.** The ENERGY DEFICIENT ENTITY shall communicate its needs to other BALANCING AUTHORITIES and market participants. Upon request from the ENERGY DEFICIENT ENTITY, the respective RELIABILITY AUTHORITY shall post the declaration of the Alert level along with the name of the ENERGY DEFICIENT ENTITY and, if applicable, its BALANCING AUTHORITY on the NERC Web site
- 2.2 Declaration Period.** The ENERGY DEFICIENT ENTITY shall update its RELIABILITY AUTHORITY of the situation at a minimum of every hour until the Alert 2 is terminated. The RELIABILITY AUTHORITY shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITY, and Transmission Providers.
- 2.3 Sharing information on resource availability.** BALANCING AUTHORITY and market participants with available resources shall immediately contact the ENERGY DEFICIENT ENTITY. This should include the possibility of selling non-firm (recallable) energy out of available operating reserves. The ENERGY DEFICIENT ENTITY shall notify the RELIABILITY AUTHORITIES of the results.

---

<sup>1</sup> For emergency, not economic, reasons.

- 2.4 Evaluating and mitigating transmission limitations.** The RELIABILITY AUTHORITIES shall review all OPERATING SECURITY LIMITS and transmission loading relief procedures in effect that may limit the ENERGY DEFICIENT ENTITY's scheduling capabilities. Where appropriate, the RELIABILITY AUTHORITIES shall inform the Transmission Providers under their purview of the pending ENERGY EMERGENCY and request that they increase their Available Transfer Capability (ATC) by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.
- 2.4.1 Notification of ATC adjustments.** Resulting increases in ATCs shall be simultaneously communicated to the ENERGY DEFICIENT ENTITY and the market via posting on the appropriate OASIS sites by the Transmission Providers.
- 2.4.2 Availability of generation redispatch options.** Available generation redispatch options shall be immediately communicated to the ENERGY DEFICIENT ENTITY by its RELIABILITY AUTHORITY.
- 2.4.3 Evaluating impact of current transmission loading relief events.** The RELIABILITY AUTHORITIES shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the ENERGY DEFICIENT ENTITY. This evaluation shall include analysis of system security and involve close communication among RELIABILITY AUTHORITIES and the ENERGY DEFICIENT ENTITY.
- 2.4.4 Initiating inquiries on reevaluating OPERATING SECURITY LIMITS.** The RELIABILITY AUTHORITIES shall consult with the BALANCING AUTHORITIES and Transmission Providers in their RELIABILITY AREAS about the possibility of reevaluating and revising OPERATING SECURITY LIMITS.
- 2.5 Coordination of emergency responses.** The RELIABILITY AUTHORITY shall communicate and coordinate the implementation of emergency operating responses.
- 2.6 ENERGY DEFICIENT ENTITY actions.** Before declaring an Alert 3, the ENERGY DEFICIENT ENTITY must make use of all available resources. This includes but is not limited to:
- 2.6.1 All available generation units are on line.** All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.
- 2.6.2 Purchases made regardless of cost.** All firm and non-firm purchases have been made, regardless of cost.
- 2.6.3 Non-firm sales recalled and contractually interruptible loads and DSM curtailed.** All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.
- 2.6.4 Operating Reserves.** Operating reserves are being utilized such that the ENERGY DEFICIENT ENTITY is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

### 3. Alert 3 – Firm load interruption imminent or in progress.

#### Circumstances:

- BALANCING AUTHORITY or LOAD SERVING ENTITY foresees or has implemented firm load obligation interruption. The available energy to the ENERGY DEFICIENT ENTITY, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

- 3.1 Continue actions from Alert 2.** The RELIABILITY AUTHORITIES, and the ENERGY DEFICIENT ENTITY, shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC web site (see paragraph 2.1), the respective RELIABILITY AUTHORITIES will, at this time, post on the web site information concerning the emergency.
- 3.2 Declaration Period.** The ENERGY DEFICIENT ENTITY shall update its RELIABILITY AUTHORITY of the situation at a minimum of every hour until the Alert 3 is terminated. The RELIABILITY AUTHORITY shall update the energy deficiency information posted on the NERC web site as changes occur and pass this information on to the affected RELIABILITY AUTHORITIES (via the RCIS), BALANCING AUTHORITIES, and Transmission Providers.
- 3.3 Use of Transmission short-time limits.** The RELIABILITY AUTHORITIES shall request the appropriate Transmission Providers within their RELIABILITY AREA to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the ENERGY DEFICIENT ENTITY.
- 3.4 Reevaluating and revising OPERATING SECURITY LIMITS.** The RELIABILITY AUTHORITY of the ENERGY DEFICIENT ENTITY shall evaluate the risks of revising OPERATING SECURITY LIMITS on the reliability of the overall transmission system. Reevaluation of OPERATING SECURITY LIMITS shall be coordinated with other RELIABILITY AUTHORITIES and only with the agreement of the BALANCING AUTHORITY or Transmission Provider whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the ENERGY DEFICIENT ENTITY who has declared an Energy Emergency Alert 3 condition. OPERATING SECURITY LIMITS shall only be revised as long as an Alert 3 condition exists or as allowed by the BALANCING AUTHORITY or Transmission Provider whose equipment is at risk. The following are minimum requirements that must be met before OPERATING SECURITY LIMITS are revised:
  - 3.4.1 ENERGY DEFICIENT ENTITY obligations.** The deficient BALANCING AUTHORITY or LOAD SERVING ENTITY must agree that, upon notification from its RELIABILITY AUTHORITY of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the INTERCONNECTION. These actions may include load shedding.
  - 3.4.2 Mitigation of cascading failures.** The RELIABILITY AUTHORITY shall use his best efforts to ensure that revising OPERATING SECURITY LIMITS would not result in any cascading failures within the INTERCONNECTION.
- 3.5 Returning to pre-emergency OPERATING SECURITY LIMITS.** Whenever energy is made available to an ENERGY DEFICIENT ENTITY such that the transmission systems can be returned to their pre-emergency OPERATING SECURITY LIMITS, the ENERGY DEFICIENT ENTITY shall notify its respective RELIABILITY AUTHORITY and downgrade the Alert.
  - 3.5.1 Notification of other parties.** Upon notification from the ENERGY DEFICIENT ENTITY that an Alert has been downgraded, the RELIABILITY AUTHORITY shall notify the affected RELIABILITY AUTHORITIES (via the RCIS), BALANCING AUTHORITIES, and Transmission

Providers that their systems can be returned to their normal OPERATING SECURITY LIMITS.

- 3.6 Reporting.** Any time an Alert 3 is declared, the ENERGY DEFICIENT ENTITY shall complete the report listed in appendix 9B, Section C and submit this report to its respective RELIABILITY AUTHORITY within two business days of downgrading or termination of the Alert. Upon receiving the report, the RELIABILITY AUTHORITY shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The RELIABILITY AUTHORITY shall present this report to the Reliability Authority Working Group at its next scheduled meeting.
- 4. Alert 0 - Termination.** When the ENERGY DEFICIENT ENTITY believes it will be able to supply its customers' energy requirements, it shall request of his RELIABILITY AUTHORITY that the EEA be terminated.
- 4.1. Notification.** The RELIABILITY AUTHORITY shall notify all other RELIABILITY AUTHORITIES via the RCIS of the termination. The RELIABILITY AUTHORITY shall also notify the affected BALANCING AUTHORITIES and TRANSMISSION PROVIDERS. The Alert 0 shall also be posted on the NERC web site if the original Alert was so posted.

### **3. C. Energy Emergency Alert 3 Report**

---

NERC Policy 9B section B paragraph 3.5 requires that a Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report it is to be sent to the RELIABILITY AUTHORITY for review within two business days of the incident.

**Requesting Balancing Authority:**

---

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

---

**Date/Time Implemented:**

---

**Date/Time Released:**

---

**Declared Deficiency Amount (MW):**

---

**Total Energy supplied by other Balancing Authority During the Alert 3 period:**

---

**Conditions that precipitated call for “Energy Deficiency Alert 3”:**

---

---

---

**If “Energy Deficiency Alert 3” had not been called, would firm load be cut? if no, explain:**

---

---

---

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

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

---

---

---

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

---

---

---

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

---

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

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

- 
- 
- 
6. Operating Reserves being utilized.

Comments:

---

---

Reported By:

Organization:

---

Title:

---

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	023		
Title	Sabotage Reporting	Operating Policy 5G	
Purpose	Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. RELIABILITY AUTHORITIES</li> <li>2. BALANCING AUTHORITIES</li> <li>3. TRANSMISSION OPERATORS</li> <li>4. GENERATOR OPERATORS</li> </ol>		
Requirements	R1 Each Reliability Authority, Balancing Authority, Transmission Operator, and Generator Operator shall have procedures for making operating personnel aware and for notifying others regarding sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.		
	R2 Each Reliability Authority, Balancing Authority, Transmission Operator, and Generator Operator shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.		
	R3 Each Reliability Authority, Balancing Authority, Transmission Operator, and Generator Operator shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.		
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	024	Policy 6 –Operations Planning Standard Version 0, Draft 1 Normal Operations	
Title	Normal Operations Planning	Operating Policy 6 “Operations Planning” Section A “Normal Operations”	
Purpose	To define the requirement that each RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR AND GENERATOR OPERATOR is to maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITY, 2. BALANCING AUTHORITY, 3. TRANSMISSION OPERATOR 4. GENERATION OPERATOR 5. LOAD SERVING ENTITY 6. TRANSMISSION SERVICE PROVIDER		
Requirements	R1 Each RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR AND GENERATOR 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 RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR AND GENERATOR OPERATOR shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected systems reliability will be maintained.	Policy 6 Introduction	
	R2 Each RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR AND GENERATOR 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	Policy 6 Introduction	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	aware of the planning purpose.		
R3	Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall plan its current-day, next-day, and seasonal operations in coordination (where confidentiality agreements allow) with neighboring RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES so that normal INTERCONNECTION operation will proceed in an orderly and consistent manner.	Policy 6A Requirement 1	
R4	Each LOAD SERVING ENTITY, TRANSMISSION SERVICE PROVIDER, and GENERATOR OPERATOR shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its host BALANCING AUTHORITY. Each BALANCING AUTHORITY and TRANSMISSION SERVICE PROVIDER shall coordinate its current-day, next-day, and seasonal operations with its TRANSMISSION OPERATOR.	Policy 6A Requirement 1.1	
R5	Each BALANCING AUTHORITY and TRANSMISSION OPERATOR shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS and with its RELIABILITY AUTHORITY.	Policy 6A Requirement 1 1.2	
R6	Each Reliability Authority, Balancing Authority, Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Policy 6A Requirement 2 2.1	
R7	Each RELIABILITY AUTHORITY, 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, and local reliability requirements.	Policy 6A Requirement 2 2.2	
R8	Each RELIABILITY AUTHORITY and BALANCING AUTHORITY shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single contingency.	Policy 6A Requirement 2 2.3	
R9	Each RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall plan to respect voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Policy 6A Requirement 2 2.4	
R10	Each BALANCING AUTHORITY shall plan to meet Interchange Schedules. All GENERATOR OPERATORS shall operate their plant(s) so as to adhere to ramp schedules.	Policy 6A Requirement 2 2.5	The Drafting Team questions the meaning of this requirement and whether it is necessary or

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
			enforceable.
	R11 Each RELIABILITY AUTHORITY, BALANCING AUTHORITY, and TRANSMISSION OPERATOR shall plan to respect all System Operating Limits (SOLs).	Policy 6A Requirement 2 2.6	
	R12 The RELIABILITY AUTHORITY and TRANSMISSION OPERATOR shall perform seasonal, next-day, and current-day BULK ELECTRIC SYSTEM studies to determine SYSTEM OPERATING LIMITS. Neighboring RELIABILITY AUTHORITIES and TRANSMISSION OPERATORS shall utilize identical SYSTEM OPERATING LIMITS for common facilities. The RELIABILITY AUTHORITY and 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 AUTHORITY.	Policy 6A Requirement 3.	
	R13 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 TTC/ATC calculation processes.	Policy 6A Requirement 4.	
	R14 At the request of the RELIABILITY AUTHORITY, BALANCING AUTHORITY, or TRANSMISSION OPERATOR, a GENERATOR OPERATOR shall perform generating real or 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 RELIABILITY AUTHORITY, BALANCING AUTHORITY, or TRANSMISSION OPERATOR operating personnel as requested.	Policy 6A Requirement 5.	
	R15 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: <ul style="list-style-type: none"> <li>• Changes in real and reactive output capabilities,</li> <li>• Automatic Voltage Regulator status and mode setting</li> </ul>	Policy 6A Requirement 6.1  Policy 6A Requirement 6.1.1 Policy 6A Requirement 6.1.2	This may be redundant with a similar requirement in Standard 009
	R16 GENERATION OPERATORS shall, at the BALANCING AUTHORITY'S OR TRANSMISSION OPERATOR'S request, provide a forecast of expected real power output to assist in operations planning (e.g. a	Policy 6A Requirement 6.2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	seven-day forecast of real output).		
	R17 TRANSMISSION OPERATORS shall, without any intentional time delay, notify their RELIABILITY AUTHORITY and BALANCING AUTHORITY of changes in capabilities and characteristics including but not limited to: <ul style="list-style-type: none"> <li>• Changes in transmission facility status</li> <li>• Changes in transmission facility rating</li> </ul>	Policy 6A Requirement 6.3	
	R18 BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall, without any intentional time delay, communicate the information described in the requirements 1-17 above to their RELIABILITY AUTHORITY.		It may be more appropriate to add this requirement to each applicable requirement above.
	R19 Neighboring RELIABILITY AUTHORITIES, 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.	Policy 6A Requirement 6.5	
	R20 The RELIABILITY AUTHORITY, BALANCING AUTHORITY and TRANSMISSION OPERATOR shall maintain accurate computer models utilized for analyzing and planning system operations.	Policy 6A Requirement 6.6	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	025	Policy 6 – Operations Planning Section B – Emergency Operations  Compliance Template P6T1	
Title	Emergency Operations Planning		
Purpose	Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR AND BALANCING AUTHORITY needs to develop, maintain, and implement a set of plans consistent with NERC Operating Policies to mitigate operating emergencies. These plans need to be coordinated with other RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS and BALANCING AUTHORITIES as appropriate.	P6 B Introduction	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITY, 2. BALANCING AUTHORITY, 3. TRANSMISSION OPERATOR		
Requirements	R1 BALANCING AUTHORITIES shall have operating agreements with adjacent BALANCING AUTHORITIES that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote BALANCING AUTHORITIES.		
	R2 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY shall be staffed with adequately trained operating personnel. Training for operating personnel shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	Policy 6B Requirement 2.	
	R3 The RELIABILITY AUTHORITY and TRANSMISSION OPERATOR shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	Policy 6B Requirement 3.	
	R4 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND	Policy 6B	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>BALANCING AUTHORITY shall:</p> <ul style="list-style-type: none"> <li>Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.</li> <li>Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.</li> <li>Develop, maintain, and implement a set of plans to mitigate operating emergencies for load shedding.</li> <li>Develop, maintain, and implement a set of plans to mitigate operating emergencies for System Restoration.</li> </ul>	<p>Requirement 4. Policy 6B Requirement 4.1 Policy 6B Requirement 4.2 Policy 6B Requirement 4.3 Policy 6B Requirement 4.4</p>	
	<p>R5 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY emergency plans shall include:</p> <ul style="list-style-type: none"> <li>Communications protocols to be used during emergencies.</li> <li>List of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC established timelines, shall be one of the controlling actions.</li> <li>The tasks to be coordinated with and among adjacent RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, AND BALANCING AUTHORITIES.</li> <li>Staffing levels for the emergency.</li> </ul>	<p>Policy 6B Requirement 5.</p> <p>Policy 6B Requirement 5.1 Policy 6B Requirement 5.2</p> <p>Policy 6B Requirement 5.3</p> <p>Policy 6B Requirement 5.4</p>	<p>The Drafting Team asks whether the list of “must” statements describing the emergency plans in Compliance Template P6T1 should be included here. Those items are listed in Policy 6B as guides, but then shown as requirements in the Compliance Template.</p> <p>The list of potential requirements is attached below.</p>
	<p>R6 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY shall annually review and update each emergency plan. The TRANSMISSION OPERATOR AND BALANCING AUTHORITY shall provide a copy of its updated emergency plans to its RELIABILITY AUTHORITY and to neighboring TRANSMISSION OPERATORS AND BALANCING AUTHORITIES. The RELIABILITY AUTHORITY shall provide a copy of its updated emergency plans to its neighboring RELIABILITY AUTHORITIES.</p>	<p>Policy 6B Requirement 6.</p>	
	<p>R7 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY shall coordinate its emergency plans with other RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, AND BALANCING AUTHORITIES as appropriate. This coordination includes the following steps, as applicable:</p> <ul style="list-style-type: none"> <li>Establish and maintain reliable communications between</li> </ul>	<p>Policy 6B Requirement 7.</p> <p>Policy 6B</p>	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	interconnected systems. <ul style="list-style-type: none"> <li>• Arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.</li> <li>• Coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)</li> <li>• Arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.</li> </ul>	Requirement 7.1 Policy 6B Requirement 7.2  Policy 6B Requirement 7.3  Policy 6B Requirement 7.4	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Potential additional elements of Requirement R5:

1. **Fuel supply and inventory.** An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel.
2. **Fuel switching.** Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.
3. **Environmental constraints.** Plans to seek removal of environmental constraints for generating units and plants.
4. **System energy use.** The reduction of the system's own energy use to a minimum.
5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. **Load management.** Implementation of load management and voltage reductions, if appropriate.
7. **Optimize fuel supply.** The operation of all generating sources to optimize the availability.
8. **Appeals to customers to use alternate fuels.** In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.
9. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
11. **Notifying IPPs.** Notification of cogeneration and independent power producers to maximize output and availability.
12. **Requests of government.** Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.
13. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.
14. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented.
15. **Utilization of Energy Emergency Alert procedures as specified in Appendix 5C.**
16. **Generation redispatch options.**
17. **Transmission reconfiguration options.**
18. **Utilization of Special Protection Schemes.**
19. **Local or INTERCONNECTION-wide transmission loading relief procedures.**
20. **Reserve sharing.**



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	021	Operating Policy 5D	
Title	Emergency Operations/Transmission		
Purpose	To ensure BALANCING AUTHORITIES AND TRANSMISSION OPERATORS take actions to mitigate SOL and IROL violations.		
Effective Date	February 8, 2005		
Applicability	1. BALANCING AUTHORITIES 2. TRANSMISSION OPERATORS		
Requirements	R1 The BALANCING AUTHORITY and TRANSMISSION OPERATOR experiencing or contributing to an SOL or IROL violation shall take immediate steps to relieve the condition, which may include firm load shedding.		
	R2 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall ensure they operate to prevent the likelihood that a disturbance, action, or non-action will result in a SOL or IROL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the BALANCING AUTHORITY and TRANSMISSION OPERATOR shall always operate the BULK ELECTRIC SYSTEM to the most limiting parameter.		
	R3 The BALANCING AUTHORITY and TRANSMISSION OPERATOR shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the BALANCING AUTHORITY or TRANSMISSION OPERATOR shall notify its RELIABILITY AUTHORITY and all neighboring BALANCING AUTHORITIES and TRANSMISSION OPERATORS impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.		
	R4 The TRANSMISSION OPERATOR shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The TRANSMISSION OPERATOR shall use the results of these analyses to immediately mitigate the SOL violation.		
Measures	Not Specified.		
Regional Differences	Not Identified.		
Compliance Monitoring	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Process			
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	022	Operating Policy 5F	
Title	Disturbance Reporting		
Purpose	Disturbances or unusual occurrences that jeopardize the operation of the BULK ELECTRIC SYSTEM, and result, or could result, in system equipment damage, or customer interruptions, shall be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, Regional Councils, NERC, and regulatory agencies entitled to the information.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. Reliability Authorities</li> <li>2. Balancing Authorities</li> <li>3. Transmission Operators</li> <li>4. Regional Councils</li> </ol>		
Requirements	R1 Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.		
	R2 Affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS shall promptly analyze BULK ELECTRIC SYSTEM disturbances.		
	R3 RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS responsible for investigating an incident shall provide a preliminary written report to their Regional Council and NERC. The affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnected Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized. Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnected Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected RELIABILITY AUTHORITY, BALANCING AUTHORITY, or TRANSMISSION OPERATOR shall notify its Regional		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report. If in the judgment of the Regional Council, after consultation with the RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS in which a disturbance occurred, a final report is required, the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Council approval.		
	R4 When a BULK ELECTRIC SYSTEM disturbance occurs, the Regional Council's OC and DAWG representatives shall make themselves available to the RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, and TRANSMISSION OPERATORS immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.		
	R5 The Regional Council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Council shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.		
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	026	Policy 6 – Operations Planning Section C – Load Shedding	
Title	Load Shedding Plans		
Purpose	After taking all other remedial steps, a RELIABILITY AUTHORITY, BALANCING AUTHORITY and TRANSMISSION OPERATOR operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION.”	Policy 6C Introduction	The Drafting Team believes that this standard confuses the distinction between planning and implementing load shedding. Policy 6 addresses operational plans and the other sections focus on planning requirements. However, Policy 6C includes both the planning and implementation of load shedding. Should the implementation requirements be moved to other standards focused on emergency operations?
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITY 2. TRANSMISSION OPERATOR 3. BALANCING AUTHORITY		
Requirements	R1 After taking all other remedial steps, a RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION.	Policy 6C Introduction	Is this requirement in the 6C intro redundant with a prior requirement?
	R2 Each TRANSMISSION OPERATOR and BALANCING AUTHORITY shall establish plans for automatic load shedding.	Policy 6C Requirement 1.	
	R3 Each TRANSMISSION OPERATOR and BALANCING AUTHORITY shall coordinate load shedding plans among other interconnected TRANSMISSION OPERATOR and BALANCING AUTHORITY AREAS.	Policy 6C Requirement 1.1	
	R4 A TRANSMISSION OPERATOR or BALANCING AUTHORITY shall initiate automatic load shedding at the time one of the following has reached an agreed-to level: frequency, rate of frequency decay,	Policy 6C Requirement 1.2.1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	027	<p>Policy 6 – Operations Planning Section D – System Restoration Plans</p> <p>P6T2 Compliance Template</p> <p>Reference Document — Electric System Restoration</p>	
Title	System Restoration Plans		
Purpose	To ensure each reliability entity develops and annually reviews its plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shut down of the system.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. RELIABILITY AUTHORITY</li> <li>2. TRANSMISSION OPERATOR</li> <li>3. BALANCING AUTHORITY</li> </ol>		
Requirements	R1 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall have and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system. This plan shall be coordinated with other RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES in the INTERCONNECTION to ensure a consistent INTERCONNECTION restoration plan.		
	R2 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY 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.	Policy 6D Requirement 1.	
	R3 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall review and update its restoration plan at least annually, and whenever it makes changes in the power system network, and to correct deficiencies found during the	Policy 6D Requirement 1.1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	simulated restoration exercises.		
	R4 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall develop restoration plans with the intent of restoring the integrity of the Interconnection.	Policy 6D Requirement 1.2	The Drafting Team believes this requirement should be clarified to indicate the restoration plan should have as a priority restoring the integrity of the Interconnection.
	R5 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall coordinate its restoration plans with neighboring RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES.	Policy 6D Requirement 1.3	
	R6 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall periodically test its telecommunication facilities needed to implement the restoration plan.	Policy 6D Requirement 1.4	
	R7 The RELIABILITY AUTHORITY, 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.	Policy 6D Requirement 2.	
	R8 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall verify its restoration procedures by actual testing or by simulation.	Policy 6D Requirement 3	
	R9 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall ensure the availability and location of black start capability within its respective RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY AREA to meet the needs of the restoration plan.	Policy 6D Requirement 4	
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review: Included as part of the on-site operational review every three years.</p> <p>Self-Assessment: Annual report to the Regional Reliability Council of plan review and/or updates.</p> <p>Reset Period: One calendar year.</p> <p>Data Retention: The OPERATING AUTHORITY must have its plan to reestablish its electric system available for a review by the Regional</p>	Compliance Template P6T2	



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	Reliability Council at all times.		
Levels of Non Compliance	Level 1 — Plan exists but is not reviewed annually. Level 2 — Plan exists but does not address one of the nine requirements. Level 3 — N/A Level 4 — Plan exists but does not address two or more of the nine requirements or there is no Restoration Plan in place.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	voltage level, rate of voltage decay, or power flow levels.		
	R5 A TRANSMISSION OPERATOR or BALANCING AUTHORITY shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Policy 6C Requirement 1.2.2	
	R6 After a TRANSMISSION OPERATOR or BALANCING AUTHORITY AREA separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the TRANSMISSION OPERATOR or BALANCING AUTHORITY shall shed additional load.	Policy 6C Requirement 1.2.3	
	R7 The TRANSMISSION OPERATOR or BALANCING AUTHORITY shall coordinate automatic load shedding throughout their TRANSMISSION OPERATOR or BALANCING AUTHORITY AREAS with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.	Policy 6C Requirement 1.2.4	
	R8 Each TRANSMISSION OPERATOR or BALANCING AUTHORITY shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The TRANSMISSION OPERATOR or BALANCING AUTHORITY shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Policy 6C Requirement 2.	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	028	Operating Policy 6 – Operations Planning Section E – Loss of Primary Control Facilities  Compliance Template P6T2	
Title	Plans for Loss of Control Center Functionality		
Purpose	Each reliability entity needs to AUTHORITIES shall have a plan to continue reliability operations in the event its control center becomes inoperable.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. TRANSMISSION OPERATOR 3. BALANCING AUTHORITIES		
Requirements	<p>R1 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:</p> <ul style="list-style-type: none"> <li>• The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.</li> <li>• The plan shall include procedures and responsibilities for providing basic tie line control and procedures and responsibilities for maintaining the status of all inter area schedules such that there is an hourly accounting of all schedules.</li> <li>• The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.</li> <li>• The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other AREAS.</li> <li>• The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of</li> </ul>	Compliance Template P6T2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>the plan.</p> <ul style="list-style-type: none"> <li>• The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.</li> <li>• The plan shall be reviewed and updated annually.</li> <li>• The functions to be coordinated with and among neighboring AREAS. (The plan should include references to coordination of actions among neighboring AREAS when the plans are implemented.)</li> <li>• Notification shall be made to other operating entities as the steps of the restoration plan are implemented.</li> <li>• Interim provisions must be included if it is expected to take in excess of one hour to implement the loss of primary control facility contingency plan.</li> </ul>		
Measures	Evidence that the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain BULK ELECTRICAL SYSTEM reliability if their primary control facility becomes inoperable.	Compliance Template P6T2	
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review: Review and evaluate the loss of primary control facility contingency plan as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY.</p> <p>Self-Certification: Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall annually, self-certify to the Regional Reliability Organization that the following criteria have been met:</p> <ol style="list-style-type: none"> <li>1. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.</li> <li>2. A set of procedures for annual review and updated for simulating and, where practical, actual testing and verification of the plan resources and procedures (<i>at least every three years</i>).</li> <li>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</li> </ol>	Compliance Template P6T2	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>exercises.</p> <p>Reset Period: One calendar year.</p> <p>Data Retention: The contingency plan for loss of primary control facility must be available for review at all times.</p>		
Levels of Non Compliance	<p>Level 1 — Plan exists but is not reviewed annually.</p> <p>Level 2 — Plan exists but does not address one of the 10 requirements.</p> <p>Level 3 — N/A</p> <p>Level 4 — Plan exists but does not address two or more of the nine requirements or there is no Restoration Plan in place.</p>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	029	Policy 7 – Telecommunications  Geomagnetic Disturbance Reference Document	
Title	Telecommunications		
Purpose	Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY must have adequate and reliable telecommunications facilities internally and with others for the exchange of INTERCONNECTION and operating information necessary to maintain reliability.	Policy 7	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. TRANSMISSION OPERATORS 3. BALANCING AUTHORITIES		
Requirements	R1 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall provide adequate and reliable telecommunications facilities internally and with other RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES for the exchange of INTERCONNECTION and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed.	Policy 7A Requirement 1.	There may be redundancy here with Policy 5A Requirement 1.
	R2 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	Policy 7A Requirement 3.	
	R3 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall provide a means to coordinate telecommunications among their respective AREAS. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the region and with other regions.	Policy 7B Requirement 1.	
	R4 Unless agreed to otherwise, each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall use English as the language for all communications between and	Policy 7B Requirement 2.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
	among operating personnel responsible for the real-time generation control and operation of the interconnected BULK ELECTRIC SYSTEM. RELIABILITY AUTHORITIES, TRANSMISSION OPERATORS, and BALANCING AUTHORITIES may use an alternate language for internal operations.		
	R5 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunications facilities.		
	R6 Each NERCNet User Organization shall adhere to the requirements in Attachment 1, “NERCNet Security Policy”.		Need to add a definition of a NERCNet User Organization to the Standards Glossary.
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

# **Attachment 1 – NERCnet Security Policy**

## ***Policy Statement***

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

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

The objectives of the NERCnet Security Policy are:

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

## ***NERC’s Security Mission Statement***

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

## ***Implementation and Responsibilities***

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

### **NERCnet User Organizations**

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

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC authorized business purposes only.
- Comply with the NERCnet Security policies, standards and guidelines as well as any procedures specified by the data owner.
- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse or non-compliance situations via RAIS or the NERC Telecommunications Manager.
- Protect the confidentiality of all user IDs and passwords.
- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.



- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

## **User Accountability and Compliance**

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

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

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.
- Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	030	Operating Policy 8 – Operating Personnel and Training Section A – Responsibility and Authority  Compliance Template P8T1	
Title	Operating Personnel Responsibility and Authority		
Purpose	RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating personnel need to have the responsibility and authority to implement real-time actions that ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM.	Policy 8A	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. TRANSMISSION OPERATORS 3. BALANCING AUTHORITIES		
Requirements	R1 RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating personnel shall have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM.	Compliance Template P8T1	
Measures	M1 Evidence that the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating personnel responsibility and authority to implement real-time actions that ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM are documented and understood. Documentation shall include: 1. A written current job description exists which states in clear and unambiguous language the responsibilities and authorities of each operating position of a RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY. The position description identifies personnel subject to the authority of the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, AND BALANCING AUTHORITY. 2. Written current job description states operating personnel are responsible for complying with the NERC Operating Policies.	Compliance Template P8T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>3. Written current job description is readily accessible in the control room environment to all operating personnel.</p> <p>4. Written operating procedures state that during emergency conditions operating personnel have the authority to take or direct timely and appropriate real-time actions, up to and including shedding of firm load to prevent or alleviate System Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY.</p>		
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review: An on-site review including interviews with RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating personnel and documentation verification will be conducted every three years. The job description that identifies the operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the BULK ELECTRIC SYSTEM during normal and emergency conditions.</p> <p>Self-certification: The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall annually complete a self-certification form developed by the RRC based on requirements 1–4 in the Measure M1.</p> <p>Reset Period: One calendar year.</p> <p>Data Retention: Permanent.</p>	Compliance Template P8T1	
Levels of Non Compliance	<p>Level 1 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY has written documentation that includes three of the four items in M1.</p> <p>Level 2 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, or BALANCING AUTHORITY has written documentation that includes two of the four items in M1.</p> <p>Level 3 — The Operating Authority has written documentation that includes one of the four items in M1.</p> <p>Level 4 — The Operating Authority has written documentation that</p>	Compliance Template P8T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	includes none of the items in M1, or the interview verification items 1 and 2 do not support the authority of the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	031	Policy 8 – Operating Personnel and Training Section B - Training	
Title	Operating Personnel Training		
Purpose	Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY needs to provide their personnel with a coordinated training program that will ensure reliable system operation.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. Reliability Authority</li> <li>2. Balancing Authority</li> <li>3. Transmission Operator</li> </ol>		
Requirements	<p>R1 A RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall have a training program for operating personnel that meets the following criteria:</p> <ol style="list-style-type: none"> <li>1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those policies, procedures, and requirements to normal, emergency, and restoration conditions for the RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating positions.</li> <li>2. The training program must include a plan for the initial and continuing training of RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating personnel that addresses required knowledge and competencies and their application in system operations.</li> <li>3. The training program must include training time for all RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY operating staff to ensure their operating proficiency.</li> <li>4. Trainers must be identified, and they must be individuals competent in both knowledge of system operations and instructional capabilities.</li> <li>5. The training program must include elements of Attachment 1 that apply to each specific RELIABILITY AUTHORITY,</li> </ol>	Policy 8B	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Draft Version 0 Standard			
Standard	032	Policy 8 – Operating Personnel and Training Section C. Certification	
Title	Operating Personnel Credentials		
Purpose	Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.		
Effective Date	February 8, 2004		
Applicability	<ol style="list-style-type: none"> <li>1. RELIABILITY AUTHORITIES</li> <li>2. TRANSMISSION OPERATORS</li> <li>3. BALANCING AUTHORITIES</li> </ol>		
Requirements	<p>R1 Each RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall staff all operating positions that meet either of the following criteria with personnel that are NERC-certified for the applicable functions:</p> <ol style="list-style-type: none"> <li>1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected BULK ELECTRIC SYSTEM.</li> <li>2. Positions directly responsible for complying with NERC standards.</li> </ol>	<p>Policy 8C Requirement 1.</p> <p>Policy 8C Requirement 1.1</p> <p>Policy 8C Requirement 1.2</p>	
Measures	<p>M1 The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY shall have NERC-Certified operating personnel on shift in required positions at all times with the following exceptions:</p> <ol style="list-style-type: none"> <li>1. While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-Certified individual filling the required position.</li> <li>2. During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four (4) hours.</li> </ol>		
Regional	None Identified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Differences			
Compliance Monitoring Process	<p>Periodic Review: An on-site review will be conducted every three years. Staffing schedules and Certification numbers will be compared to ensure that positions that require NERC-Certified System Operators were covered as required. Certification numbers from the Operating Authority will be compared with NERC records.</p> <p>Exception Reporting: Any violation of the standard must be reported to the RRC who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.</p> <p>Reset Period: One calendar month without a violation.</p> <p>Data Retention: Present calendar year plus previous calendar year staffing plan.</p>		
Levels of Non Compliance	<p>Level 1 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.</p> <p>Level 2 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.</p> <p>Level 3 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.</p> <p>Level 4 — The RELIABILITY AUTHORITY, TRANSMISSION OPERATOR, and BALANCING AUTHORITY did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.</p>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	033	Operating Policy 9 – Reliability Authority Standards Section A. Responsibilities – Authorization  Compliance Template P9T3	
Title	Reliability Coordination – Responsibilities, Authorities, and Agreements		
Purpose	RELIABILITY AUTHORITIES must have the authority, plans, and agreements in place to immediately direct reliability entities within their RELIABILITY AUTHORITY AREA to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a RELIABILITY AUTHORITY delegates tasks to others, the RELIABILITY AUTHORITY retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the RELIABILITY AUTHORITY does not act in a manner that that favors one market participant over another.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES		
Requirements	R1 Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more RELIABILITY AUTHORITIES to continuously assess transmission security and coordinate emergency operations among the operating entities within the region and across the regional boundaries.		Requirements 1 and 2 establish the foundation for reliability coordination. Standards previously assigned to Reliability Coordinators have been assigned to RELIABILITY AUTHORITIES to facilitate implementation of the Functional Model. For areas in which the current Reliability Coordinator and the RELIABILITY AUTHORITY functions are with the same entity, the translation of Operating Policy 9 to standards is straightforward. For areas that intend to assign RELIABILITY AUTHORITY functions to current Control Areas, those RELIABILITY



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
			AUTHORITIES need to accept responsibility for the reliability coordination standards (33 to 41) while recognizing tasks may be assigned to others, including “upwardly” to a Reliability Coordinator. Accountability for compliance with standards, however, remains with the RELIABILITY AUTHORITY.
	R2 A RELIABILITY AUTHORITY shall have in place and comply with a reliability plan approved by the NERC Operating Committee.		
	R3 The RELIABILITY AUTHORITY shall have clear decision-making authority to act and to direct actions to be taken by BALANCING AUTHORITIES, TRANSMISSION OPERATORS, GENERATOR OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES within its RELIABILITY AUTHORITY AREA to preserve the integrity and reliability of the BULK ELECTRIC SYSTEM. These actions shall be taken without delay, and no longer than 30 minutes.	Policy 9A Requirement 1.2	
	R4 RELIABILITY AUTHORITIES that delegate tasks to other entities shall have formal operating agreements with entity to which tasks are delegated. The RELIABILITY AUTHORITY shall verify that all delegated tasks are understood, communicated, and addressed within its RELIABILITY AUTHORITY AREA. All responsibilities for complying with NERC and regional standards shall remain with the RELIABILITY AUTHORITY.	Policy 9B Requirement 1	
	R5 The RELIABILITY AUTHORITY shall list within its reliability plan all entities to which RELIABILITY AUTHORITY tasks have been delegated.	Policy 9B Requirement 2	
	R6 The RELIABILITY AUTHORITY shall verify that all delegated tasks are carried out by NERC-certified RELIABILITY AUTHORITY operating personnel.	Policy 9B Requirement 3	
	R7 The RELIABILITY AUTHORITY shall have clear, comprehensive coordination agreements with adjacent RELIABILITY AUTHORITIES to ensure that SOL or IROL violation mitigation requiring actions in adjacent RELIABILITY AUTHORITY AREAS are coordinated.	Policy 9H Requirement 1	
	R8 BALANCING AUTHORITIES, TRANSMISSION OPERATORS, GENERATOR OPERATORS, TRANSMISSION SERVICE PROVIDERS,	Policy 9A Requirement 3	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES shall comply with RELIABILITY AUTHORITY directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the BALANCING AUTHORITY, TRANSMISSION OPERATOR, GENERATOR OPERATOR, TRANSMISSION SERVICE PROVIDER, LOAD-SERVING ENTITY, or PURCHASING-SELLING ENTITY must immediately inform the RELIABILITY AUTHORITY of the inability to perform the directive so that the RELIABILITY AUTHORITY may implement alternate remedial actions.		
	R9 The RELIABILITY AUTHORITY shall act in the interests of reliability for the overall RELIABILITY AUTHORITY AREA and its INTERCONNECTION, before the interests of any other entity.	Policy 9A Requirement 2	
Measures	M1 Documentation must clearly show that the RELIABILITY AUTHORITIES have the authority to immediately direct operating entities within their RELIABILITY AUTHORITY AREA to re-dispatch generation, reconfigure transmission, manage interchange transactions, or reduce system demand to mitigate SOL and IROL violations to return the system to a reliable state.	Compliance Template P9T3	
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review</p> <p>The Regional Reliability Organization shall review the RELIABILITY AUTHORITY documentation and the agreements with operating entities that delineate the authority of the RELIABILITY AUTHORITY to immediately direct actions of the operating entities in its RELIABILITY AUTHORITY AREA to mitigate SOL and IROL violations to return the system to a reliable state.</p> <p>Reset Period: One year without a violation from the time of the violation.</p> <p>Data Retention: Documentation must be available at all times.</p>	Compliance Template P9T3	
Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — RELIABILITY AUTHORITY does not have documentation of agreements with all the operating entities in their RELIABILITY AUTHORITY AREA to authenticate the authority of the RELIABILITY AUTHORITY.</p>	Compliance Template P9T3	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	Level 4 — The RELIABILITY AUTHORITY does not have the authority to direct all the operating entities in its RELIABILITY AUTHORITY AREA to take actions to mitigate SOL and IROL violations to return the system to a reliable state.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	034	Policy 9 Section I Facilities	
Title	Reliability Coordination – Facilities		
Purpose	RELIABILITY AUTHORITIES need information, tools and other capabilities to perform their responsibilities.		Portions of this standard should be moved to Reliability Authority certification criteria in a later version of the standards.
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES		
Requirements	R1 RELIABILITY AUTHORITIES shall have adequate communications (voice and data links) to appropriate entities within its RELIABILITY AUTHORITY AREA, which are staffed and available to act in addressing a real time emergency condition.	Policy 9I Requirement 1.1	This requirement could be moved to Standard 029.
	R2 The RELIABILITY AUTHORITY shall determine the data requirements to support its reliability coordination tasks and shall request such data from its BALANCING AUTHORITIES, TRANSMISSION OPERATORS, TRANSMISSION OWNERS, GENERATION OWNERS, GENERATION OPERATORS, and LOAD-SERVING ENTITIES or ADJACENT RELIABILITY AUTHORITIES.	Policy 9H Requirement 2.	Related to Standard 029.
	R3 The RELIABILITY AUTHORITY or its BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall provide, or arrange provisions for, data exchange to other RELIABILITY AUTHORITIES or BALANCING AUTHORITIES AND TRANSMISSION OPERATORS via a secure network.	Policy 9H Requirement 3.	Related to Standard 029  A clearer version of this requirement may be: Upon request, RELIABILITY AUTHORITIES shall, via the ISN, exchange with each other operating data that is necessary to allow the RELIABILITY AUTHORITIES to perform their operational reliability assessments and coordinate their reliable operations. RELIABILITY AUTHORITIES shall share with each other the types of data as listed in Attachment A, unless otherwise agreed to.  The Drafting Team asks: do TRANSMISSION OPERATORS and

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
			BALANCING AUTHORITIES have obligations to supply RELIABILITY AUTHORITY information through the NERC SDX?
	R4 RELIABILITY AUTHORITIES shall have multi-directional communications capabilities between it and its BALANCING AUTHORITIES and TRANSMISSION OPERATORS and also between it and its neighboring RELIABILITY AUTHORITIES for both voice and data exchange, as required to meet reliability needs of the INTERCONNECTION.	Policy 9I Requirement 1.2	
	R5 RELIABILITY AUTHORITIES shall have detailed real-time monitoring capability of their RELIABILITY AUTHORITY AREA and sufficient monitoring capability of their surrounding RELIABILITY AUTHORITY AREAS to ensure that potential or actual SOL or IROL violations are identified. RELIABILITY AUTHORITIES shall have monitoring systems that provide information that can be easily understood and interpreted by the RELIABILITY AUTHORITY, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure.	Policy 9I Requirement 1.3	
	R6 RELIABILITY AUTHORITIES shall monitor BULK ELECTRIC SYSTEM elements (generators, transmission lines, busses, transformers, breakers, etc.) that could result in SOL or IROL violations within their RELIABILITY AUTHORITY AREA. RELIABILITY AUTHORITIES shall monitor both real and reactive power system flows, and operating reserves, and the status of BULK ELECTRIC SYSTEM elements that are or could be critical to SOLs and IROLs and system restoration requirements within their RELIABILITY AUTHORITY AREA.	Policy 9I Requirement 1.3.1	
	R7 The RELIABILITY AUTHORITY shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage) and wide area overview displays.	Policy 9I Requirement 1.4.1	
	R8 The RELIABILITY AUTHORITY shall continuously monitor its RELIABILITY AUTHORITY AREA. The RELIABILITY AUTHORITY shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. The RELIABILITY AUTHORITY shall ensure SOL and IROL monitoring and	Policy 9I Requirement 1.4.2	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
	derivations continue if the main monitoring system is unavailable.		
	R9 The RELIABILITY AUTHORITY shall control RELIABILITY AUTHORITY analysis tools, including approvals for planned maintenance. The RELIABILITY AUTHORITY shall have procedures in place to mitigate the affects of analysis tool outages.	Policy 9I Requirement 1.4.3	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	035	Operating Policy 9 – Reliability Authority Procedures Section E – Current Day Operations	
Title	Reliability Coordination – Wide Area View		
Purpose	The RELIABILITY AUTHORITY must have a wide area view of its own RELIABILITY AUTHORITY AREA and that of neighboring RELIABILITY AUTHORITIES.	Policy 9A Requirement 1.1	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES		
Requirements	R1 The RELIABILITY AUTHORITY shall monitor all BULK ELECTRIC SYSTEM facilities, including sub-transmission information, within its RELIABILITY AUTHORITY AREA and adjacent RELIABILITY AUTHORITY AREAS as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the RELIABILITY AUTHORITY is able to determine any potential SOL and IROL violations within its RELIABILITY AUTHORITY AREA.	Policy 9E Requirement 1.1	
	R2 When a neighboring RELIABILITY AUTHORITY is aware of an external operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, the neighboring RELIABILITY AUTHORITY shall contact the RELIABILITY AUTHORITY in whose RELIABILITY AUTHORITY AREA the operational concern was observed. The two RELIABILITY AUTHORITIES shall coordinate any actions, including emergency assistance, required to mitigate the operational concern.	Policy 9E Requirement 1.1.1	
	R3 The RELIABILITY AUTHORITY shall know the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. RELIABILITY AUTHORITIES shall also know the status of any facilities that may be required to assist area restoration objectives.	Policy 9E Requirement 1.2	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Monitoring Process			
Levels of Non Compliance	Not Specified.		



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	036	Operating Policy 9 Section J – Staffing	
Title	Reliability Coordination - Staffing		
Purpose	RELIABILITY AUTHORITIES must have sufficient, competent staff to perform the RELIABILITY AUTHORITY functions		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES		
Requirements	R1 The RELIABILITY AUTHORITY shall be staffed with adequately trained and NERC-certified RELIABILITY AUTHORITY operators, 24 hours per day, seven days per week. All RELIABILITY AUTHORITY operating personnel shall complete a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	Policy 9J Requirement 1.1	
	R2 RELIABILITY AUTHORITY operating personnel shall have a comprehensive understanding of the RELIABILITY AUTHORITY AREA and interactions with neighboring RELIABILITY AUTHORITY AREAS.	Policy 9J Requirement 1.2	
	R3 RELIABILITY AUTHORITY operating personnel shall have an extensive understanding of the BALANCING AUTHORITIES, TRANSMISSION OPERATORS, and GENERATION OPERATORS within the RELIABILITY AUTHORITY AREA, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions of those entities.	Policy 9J Requirement 1.2	
	R4 The RELIABILITY AUTHORITY operating personnel shall place particular attention on SOLs and IROLs and intertie facility limits. The RELIABILITY AUTHORITY shall ensure protocols are in place to allow the RELIABILITY AUTHORITY’S operating personnel to have the best available information at all times.	Policy 9J Requirement 1.2	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	037	Standard based on Compliance Template P9T1 References to Policy 9 Section D are identified.	
Title	Reliability Coordination –Operations Planning		
Purpose	Each RELIABILITY AUTHORITY must conduct next-day reliability analyses for its RELIABILITY AUTHORITY AREA to ensure the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and contingency event conditions. System studies shall be conducted to highlight potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc., and plans developed to alleviate SOL and IROL violations.		
Effective Date	February 8, 2005		
Applicability	<ol style="list-style-type: none"> <li>1. RELIABILITY AUTHORITIES</li> <li>2. BALANCING AUTHORITIES</li> <li>3. TRANSMISSION OPERATORS</li> <li>4. TRANSMISSION SERVICE PROVIDER</li> <li>5. TRANSMISSION OWNER</li> <li>6. GENERATOR OWNER</li> <li>7. GENERATOR OPERATOR</li> <li>8. LOAD-SERVING ENTITY</li> </ol>		
Requirements	R1 The RELIABILITY AUTHORITY shall conduct next-day reliability analyses for its RELIABILITY AUTHORITY AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and CONTINGENCY event conditions. The RELIABILITY AUTHORITY shall conduct contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.	Policy 9D Requirement 1.1	
	R2 The RELIABILITY AUTHORITY shall pay particular attention to parallel flows to ensure one RELIABILITY AUTHORITY AREA does not place an unacceptable or undue BURDEN on an adjacent RELIABILITY AUTHORITY AREA.		
	R3 The RELIABILITY AUTHORITY shall, in conjunction with its TRANSMISSION OPERATORS and BALANCING AUTHORITIES, develop action plans that may be required including reconfiguration of the transmission system, re-dispatching of generation, reduction	Compliance Template P9T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	or curtailment of INTERCHANGE TRANSACTIONS, or reducing load to return transmission loading to within acceptable SOLs or IROLs.		
	R4 Each BALANCING AUTHORITY, TRANSMISSION OWNER, TRANSMISSION OPERATOR, GENERATION OWNER, GENERATION OPERATOR, and LOAD-SERVING ENTITY in the RELIABILITY AUTHORITY AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.		
	R5 The RELIABILITY AUTHORITY shall share the results of its system studies, when conditions warrant or upon request, with other RELIABILITY AUTHORITIES, and BALANCING AUTHORITIES, TRANSMISSION OPERATORS, GENERATION OPERATORS, AND TRANSMISSION SERVICE PROVIDERS within its RELIABILITY AUTHORITY AREA. The RELIABILITY AUTHORITY shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection, and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.	Policy 9D Requirement 4.	
	R6 When conditions warrant, the RELIABILITY AUTHORITY shall initiate a conference call or other appropriate communications to address the results of its reliability analyses.	Policy 9D Requirement 5.	
	R9 If the results of these studies indicate potential SOL or IROL violations, the RELIABILITY AUTHORITIES shall issue the appropriate alerts via the Reliability Authority Information System (RAIS) and direct their BALANCING AUTHORITIES, TRANSMISSION SERVICE PROVIDERS and TRANSMISSION OPERATORS to take any necessary action the RELIABILITY AUTHORITY deems appropriate to address the potential SOL or IROL violation.	Policy 9D Requirement 6.	
	R10 The BALANCING AUTHORITY, TRANSMISSION SERVICE PROVIDER and TRANSMISSION OPERATOR shall comply with the directives of its RELIABILITY AUTHORITY based on the next day assessments in the same manner in which it would comply during real time operating events.	Policy 9D Requirement 7.	
Measures	M1 Evidence that the RELIABILITY AUTHORITY conducted next-day contingency analyses for its RELIABILITY AUTHORITY AREA to ensure that the BULK ELECTRIC SYSTEM could be operated reliably in anticipated normal and contingency event conditions.	Compliance Template P9T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Regional Differences	None Identified.		
Compliance Monitoring Process	<p>Periodic Review: Entities will be selected for on-site audit at least every three years. For a selected 30-day period, in the previous three calendar months prior to the on site audit, RELIABILITY AUTHORITIES will be asked to provide documentation showing that next-day security analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.</p> <p>Self-Certification: Each RELIABILITY AUTHORITY must annually, self-certify compliance to its Regional Reliability Organization to the Requirements 1 and 2 of the Compliance Assessment Notes.</p> <p>Exception Reporting: RELIABILITY AUTHORITIES will prepare a monthly report to the Regional Reliability Organization, for each month that Requirement 1 system studies were not conducted, indicating the dates that studies were not done and the reason why.</p> <p>Reset Period: One year without a violation from the time of the violation.</p> <p>Data Retention: Documentation shall be available for 3 months that provides verification that system studies were performed as required.</p>	Compliance Template P9T1	
Levels of Non Compliance	<p>Level 1 — Requirement 1 system studies were not conducted for one day in a calendar month and/or the Requirement 2 action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.</p> <p>Level 2 — Requirement 1 system studies were not conducted for 2-3 days in a calendar month and/or the Requirement 2 action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.</p> <p>Level 3 — Requirement 1 system studies were not conducted for 4-5 days in a calendar month and/or the Requirement 2 action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING</p>	Compliance Template P9T1	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	<p>LIMIT violations.</p> <p>Level 4 — Requirement 1 system studies were not conducted for more than 5 days in a calendar month and/or the Requirement 2 action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.</p>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
ID Number	038	Policy 9 Section E. Current Day Operations	
Title	Reliability Coordination – Current Day Operations		
Purpose	The RELIABILITY AUTHORITY must be continuously aware of conditions within its RELIABILITY AUTHORITY AREA and include this information in its reliability assessments. The RELIABILITY AUTHORITY must monitor BULK ELECTRIC SYSTEM parameters that may have significant impacts upon the RELIABILITY AUTHORITY AREA and with neighboring RELIABILITY AUTHORITY AREAS.		
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. BALANCING AUTHORITIES 3. TRANSMISSION OPERATORS 4. TRANSMISSION SERVICE PROVIDERS		
Requirements	<p>R1 The RELIABILITY AUTHORITY shall monitor its RELIABILITY AUTHORITY AREA parameters, including but not limited to the following:</p> <ul style="list-style-type: none"> <li>• Current status of BULK ELECTRIC SYSTEM elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.</li> <li>• Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL violation including the plan's viability and scope.</li> <li>• Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL including the plan's viability and scope.</li> <li>• System real and reactive reserves (actual versus required).</li> <li>• Capacity and energy adequacy conditions.</li> <li>• Current ACE for all its BALANCING AUTHORITIES.</li> <li>• Current local or transmission loading relief procedures in effect.</li> <li>• Planned generation dispatches.</li> <li>• Planned transmission or generation outages.</li> <li>• Contingency events.</li> </ul>	<p>Policy 9E Requirement 1.3</p> <p>Policy 9E Requirement 1.3.1</p> <p>Policy 9E Requirement 1.3.2</p> <p>Policy 9E Requirement 1.3.3</p> <p>Policy 9E Requirement 1.3.4</p> <p>Requirement 1.3.5</p> <p>Requirement 1.3.6</p> <p>Requirement 1.3.7</p> <p>Requirement 1.3.8</p> <p>Requirement 1.3.9</p> <p>Requirement 1.3.10</p>	
	R2 The RELIABILITY AUTHORITY shall be aware of all INTERCHANGE	Policy 9E	Note: This requirement is

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	TRANSACTIONS that wheel through, source, or sink in its RELIABILITY AUTHORITY AREA and make that INTERCHANGE TRANSACTION information available to all RELIABILITY AUTHORITIES in the INTERCONNECTION.	Requirement 1.4.1	satisfied by the Interchange Distribution Calculator and E-Tag process for the Eastern Interconnection.
R3	As portions of the transmission system approach or exceed SOLs or IROLs, the RELIABILITY AUTHORITY shall work with the TRANSMISSION OPERATORS and BALANCING AUTHORITIES to evaluate and assess any additional INTERCHANGE SCHEDULES that would violate those limits. If the potential or actual IROL violation cannot be avoided through proactive intervention, the RELIABILITY AUTHORITY shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The RELIABILITY AUTHORITY shall be able to utilize all resources, including load shedding, in addressing a potential or actual IROL violation.	Policy 9E Requirement 1.4.2	
R4	The RELIABILITY AUTHORITY shall monitor BALANCING AUTHORITY parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standards requirements. If necessary, the RELIABILITY AUTHORITY shall direct the BALANCING AUTHORITIES in the RELIABILITY AUTHORITY AREA to arrange for assistance from neighboring BALANCING AUTHORITIES. The RELIABILITY AUTHORITY shall issue Energy Emergency Alerts, as needed, and at the request of BALANCING AUTHORITIES.	Policy 9E Requirement 1.4.3	
R5	The RELIABILITY AUTHORITY shall identify the cause of the potential or actual SOL or IROL violations. The RELIABILITY AUTHORITY shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The RELIABILITY AUTHORITY shall be able to utilize all resources, including load shedding, in addressing an IROL violation.	Policy 9E Requirement 1.4.4	
R6	The RELIABILITY AUTHORITY shall inform all BALANCING AUTHORITIES within its RELIABILITY AUTHORITY AREA of the start and end times for time error corrections.	Policy 9E Requirement 1.4.5	
R7	Only the INTERCONNECTION TIME MONITOR shall be able to modify scheduled Interconnection frequency to implement a time error correction, and only a RELIABILITY AUTHORITY can be the Interconnection Time Monitor.	Policy 9E Requirement 1.4.5	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	R8 The RELIABILITY AUTHORITY shall ensure all BALANCING AUTHORITIES, TRANSMISSION OPERATORS, and GENERATION OPERATORS are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.		
	R9 The RELIABILITY AUTHORITY shall participate in NERC hotline discussions, assist in the assessment of reliability of the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The RELIABILITY AUTHORITY shall disseminate such information within its RELIABILITY AUTHORITY AREA.	Policy 9E Requirement 1.4.6	
	R10 The RELIABILITY AUTHORITY shall monitor system frequency and its BALANCING AUTHORITIES' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The BALANCING AUTHORITIES and TRANSMISSION OPERATORS shall utilize all resources, including firm load shedding, as directed by a RELIABILITY AUTHORITY to relieve the emergent condition.	Policy 9E Requirement 1.4.7	
	R11 The RELIABILITY AUTHORITY shall coordinate with other RELIABILITY AUTHORITIES and BALANCING AUTHORITIES, GENERATOR OPERATORS and TRANSMISSION OPERATORS, as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The RELIABILITY AUTHORITY shall coordinate pending generation and transmission maintenance outages with other RELIABILITY AUTHORITIES and BALANCING AUTHORITIES, GENERATOR OPERATORS and TRANSMISSION OPERATORS, as needed in both the real time and next day reliability analysis timeframes.	Policy 9E Requirement 1.4.8	
	R12 As necessary, the RELIABILITY AUTHORITY shall assist the BALANCING AUTHORITIES in its RELIABILITY AUTHORITY Area in arranging for assistance from neighboring RELIABILITY AUTHORITY AREAS or BALANCING AUTHORITIES.	Policy 9E Requirement 1.4.9	
	R13 The RELIABILITY AUTHORITY shall identify sources of large Area Control Errors that may be contributing to frequency, time error, or inadvertent interchange and shall discuss corrective actions with the appropriate BALANCING AUTHORITY. If a frequency, time error, or inadvertent problem occurs outside of the RELIABILITY AUTHORITY AREA, the RELIABILITY AUTHORITY shall initiate a NERC hotline call to discuss the frequency, time error, or inadvertent interchange with other RELIABILITY AUTHORITIES. The RELIABILITY	Policy 9E Requirement 1.4.10	



Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	AUTHORITY shall direct its BALANCING AUTHORITY to comply with CPS and DCS.		
R14	Whenever a Special Protection System that may have an inter-BALANCING AUTHORITY, inter-TRANSMISSION OPERATOR, or inter-RELIABILITY AUTHORITY Area impact (e.g. could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the RELIABILITY AUTHORITIES shall be aware of the impact of the operation on inter-Area flows. The TRANSMISSION OPERATOR shall immediately inform the RELIABILITY AUTHORITY of the status of the Special Protection System including any degradation or potential failure to operate as expected.	Policy 9E Requirement 1.4.11	
R15	The RELIABILITY AUTHORITY shall ensure that all BALANCING AUTHORITIES, GENERATOR OPERATORS, TRANSMISSION OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES operate to prevent the likelihood that a disturbance, action, or non-action in its RELIABILITY AUTHORITY AREA will result in a SOL or IROL violation in another area of the INTERCONNECTION. In instances where there is a difference in derived limits, the RELIABILITY AUTHORITY and its BALANCING AUTHORITIES, GENERATOR OPERATORS, TRANSMISSION OPERATORS, TRANSMISSION SERVICE PROVIDERS, LOAD-SERVING ENTITIES, and PURCHASING-SELLING ENTITIES shall always operate the BULK ELECTRIC SYSTEM to the most limiting parameter.	Policy 9C Requirement 1.3	
R16	The RELIABILITY AUTHORITY shall make known to TRANSMISSION SERVICE PROVIDERS within its RELIABILITY AUTHORITY AREA, SOLs or IROLs within its wide area view. The TRANSMISSION SERVICE PROVIDERS shall respect these SOLs or IROLs in accordance with filed tariffs and regional TTC/ATC calculation processes.	Policy 9C Requirement 1.5	
R17	The RELIABILITY AUTHORITY shall issue directives in a clear, concise, definitive manner. The RELIABILITY AUTHORITY shall receive a response from the person receiving the directive that repeats the information given. The RELIABILITY AUTHORITY shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.	Policy 9C Requirement 1.6	This requirement is identical to one in Standard 029 and should be deleted in Version 0.
R18	The RELIABILITY AUTHORITY who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its RELIABILITY AUTHORITY AREA shall issue an alert to all	Policy 9E Requirement 1.5	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	impacted BALANCING AUTHORITIES and TRANSMISSION OPERATORS in its RELIABILITY AUTHORITY AREA, and all impacted RELIABILITY AUTHORITIES within the INTERCONNECTION via the Reliability Authority Information System without delay. The receiving RELIABILITY AUTHORITY shall disseminate this information to its impacted BALANCING AUTHORITIES and TRANSMISSION OPERATORS. The RELIABILITY AUTHORITY shall notify all impacted BALANCING AUTHORITIES, TRANSMISSION OPERATORS and RELIABILITY AUTHORITIES when the transmission problem has been mitigated.		
	R19 The RELIABILITY AUTHORITY shall confirm reliability assessment results and determine the effects within its own and adjacent RELIABILITY AUTHORITY AREAS. The RELIABILITY AUTHORITY shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary as to always act in the best interests of the Interconnection at all times.	Policy 9C Requirement 1.6	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	039	Compliance Template P9T2  Policy 9 Section F	
Title	Reliability Coordination – Transmission Loading Relief		
Purpose	Regardless of the process it uses, the RELIABILITY AUTHORITY must direct its BALANCING AUTHORITIES and TRANSMISSION OPERATORS to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. The RELIABILITY AUTHORITY 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.	Policy 9F Requirement 1.	
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITIES 2. TRANSMISSION OPERATORS 3. BALANCING AUTHORITIES		
Requirements	R1 A RELIABILITY AUTHORITY shall take appropriate actions in accordance with established policies, procedures, authority and expectations, to relieve transmission loading.	Compliance Template P9T2	
	R2 For a transmission system within its RELIABILITY AUTHORITY AREA the RELIABILITY AUTHORITY shall, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure.	Policy 9F Requirement 3.1	For Version 0, the Drafting Team intends to attach the existing TLR procedures and equivalent congestion relief procedures in the Policy 9 appendices. Work is in progress to translate these appendices to the Functional Model language. The Drafting Team is requesting WECC and ERCOT to evaluate and update appendices 9C2 and 9C3 respectively.
	R3 The RELIABILITY AUTHORITY may use local transmission loading relief or congestion management procedures, provided the TRANSMISSION OPERATOR experiencing the potential or actual IROL violation is a party to those procedures.	Policy 9F Requirement 3.2	
	R4 A RELIABILITY AUTHORITY may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the RELIABILITY AUTHORITY shall follow the curtailments as directed	Policy 9F Requirement 3.3	

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	by the Interconnection-wide procedure. A RELIABILITY AUTHORITY 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 AUTHORITIES shall comply with the provisions of the INTERCONNECTION-wide procedure including action by RELIABILITY AUTHORITIES in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.	Policy 9F Requirement 3.4	
	R6 During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY AUTHORITIES and BALANCING AUTHORITIES shall comply with interchange scheduling standards.	Policy 9F Requirement 3.5	
	R7 The TRANSMISSION OPERATOR experiencing a potential or actual SOL violation on the transmission system within its AREA shall, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or may request it’s RELIABILITY AUTHORITY to issue an INTERCONNECTION-wide procedure. When implemented, all TRANSMISSION OPERATORS and RELIABILITY AUTHORITIES shall comply with the provisions of the INTERCONNECTION-wide procedure including action by RELIABILITY AUTHORITIES in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.	Policy 9F Requirement 4	
Measures	M1 If required, an investigation will be conducted to determine if appropriate actions were taken in accordance with established policies, procedures, authority and expectations, to relieve transmission loading including notifying appropriate RELIABILITY AUTHORITIES and operating entities to curtail INTERCHANGE TRANSACTIONS.	Compliance Template P9T2	
Regional Differences	None Identified.		
Compliance Monitoring Process	The RRC or NERC may initiate an investigation if there is a complaint that an entity has not implemented relief procedures in accordance with the requirements identified in the Compliance Assessment Notes.  Reset Period: One month without a violation.	Compliance Template P9T2	
Levels of Non Compliance	The RELIABILITY AUTHORITY must follow the following requirements when relief of transmission congestion is required:	Compliance Template P9T2	

Proposed Draft Version 0 Standard Language	Existing Document References	Comments
<ul style="list-style-type: none"> <li>Implementing relief procedures. If transmission loading progresses or is projected to violate a SOL or IROL, the RELIABILITY AUTHORITY will perform the following procedures as necessary:</li> <li>Selecting transmission loading relief procedure. The RELIABILITY AUTHORITY experiencing a potential or actual SOL or IROL violation on the transmission system within its RELIABILITY AUTHORITY AREA shall, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix 9C1, 9C2, or 9C3.</li> <li>Using local transmission loading relief procedure. The RELIABILITY AUTHORITY 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.</li> <li>Using a local procedure with an INTERCONNECTION-wide procedure. A RELIABILITY AUTHORITY may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the RELIABILITY AUTHORITY is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY AUTHORITY 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.</li> <li>Complying with procedures. When implemented, all RELIABILITY AUTHORITIES shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY AUTHORITIES in other INTERCONNECTIONS to for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.</li> <li>Complying with interchange policies. During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY AUTHORITIES and operating entities shall comply with the Interchange Scheduling Standards.</li> <li>For the Eastern Interconnection, TLR Procedure notification documentation, operator logs of sink and neighbor BALANCING</li> </ul>		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
	AUTHORITIES as well as related electronic communications are subject to field review.		

Proposed Draft Version 0 Standard Language		Existing Document References	Comments
Standard	040		
Title	Reliability Coordination - System Restoration	Policy 9 Section G System Restoration	
Purpose	The RELIABILITY AUTHORITY must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.		Restoration planning is addressed in Standard 027. Redundancies with the requirements in this standard should be evaluated and consideration given to merging the standards in Version 0. The preferred approach may be to have one standard focused on restoration planning and another on implementation.
Effective Date	February 8, 2005		
Applicability	1. RELIABILITY AUTHORITY		
Requirements	R1 The RELIABILITY AUTHORITY shall be aware of the restoration plan of each TRANSMISSION OPERATOR in its RELIABILITY AUTHORITY AREA in accordance with NERC and regional requirements.	Policy 9G Requirement 1.	This requirement is redundant with Standard 027.
	R2 The RELIABILITY AUTHORITY shall monitor restoration progress and coordinate any needed assistance.	Policy 9G Requirement 1.	
	R3 The RELIABILITY AUTHORITY shall have a RELIABILITY AUTHORITY AREA restoration plan that provides coordination between individual TRANSMISSION OPERATOR restoration plans and that ensures reliability is maintained during system restoration events.	Policy 9G Requirement 2.	
	R4 The RELIABILITY AUTHORITY shall serve as the primary contact for disseminating information regarding restoration to neighboring RELIABILITY AUTHORITIES and BALANCING AUTHORITIES or TRANSMISSION OPERATORS not immediately involved in restoration.	Policy 9G Requirement 3.	
	R5 RELIABILITY AUTHORITIES shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a BURDEN on adjacent BALANCING AUTHORITY, TRANSMISSION OPERATOR, or RELIABILITY AUTHORITY AREAS.	Policy 9G Requirement 4.	

<b>Proposed Draft Version 0 Standard Language</b>		<b>Existing Document References</b>	<b>Comments</b>
	R6 The RELIABILITY AUTHORITY shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.	Policy 9G Requirement 4.1	
Measures	Not Specified.		
Regional Differences	None Identified.		
Compliance Monitoring Process	Not Specified.		
Levels of Non Compliance	Not Specified.		



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	051	Compliance Templates I.A.M1 I.A.M2 I.A.M3 I.A.M4	I. System Adequacy and Security  A. Transmission Systems	
Title	Transmission System Adequacy and Security	Section	I. System Adequacy and Security  A. Transmission Systems	
Purpose	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.	Introduction for I.A	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.	Last paragraph of Introduction for I.A
Effective Date	February 8, 2005	Approval Dates	CTTF Revised Compliance Templates I.A.M1, I.A.M2, I.A.M3 and I.A.M4 – NERC BOT approved April 2, 2004	
Standard Applicability	For Sections 1, 2, 3 and 4:  Planning Authority and Transmission Planner.	Applicability	I.A.M1 - Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS). I.A.M2 - Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS). I.A.M3 - Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS). I.A.M4 - Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS).	
Section 1	System performance assessment under normal (no contingency) conditions	Brief Descriptions I.A.M1	System performance under normal (no contingency) conditions	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category A of Table 1 (no contingencies) that addresses the plan year being assessed,</p> <p>4. Address any planned upgrades needed to meet the performance requirements of Category A.</p> <p>System Simulation Study/Testing Methods</p> <p>System simulation studies/testing shall (as agreed to by the Region):</p> <ol style="list-style-type: none"><li>1. Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li><li>2. Be conducted annually unless changes to system conditions do not warrant such analyses.</li><li>3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li><li>4. Have established normal (pre-contingency) operating procedures in place.</li><li>5. Have all projected firm transfers modeled.</li><li>6. Be performed for selected demand levels over the range of forecast system demands.</li></ol>	I.A.M1 System Simulation Study/Testing Methods	<p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category A of Table 1 (no contingencies) that addresses the plan year being assessed,</li><li>4. Address any planned upgrades needed to meet the performance requirements of Category A.</li></ol> <p>System Simulation Study/Testing Methods</p> <p>System simulation studies/testing shall (as agreed to by the Region):</p> <ol style="list-style-type: none"><li>1. Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li><li>2. Be conducted annually unless changes to system conditions do not warrant such analyses.</li><li>3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li><li>4. Have established normal (pre-contingency) operating procedures in place.</li><li>5. Have all projected firm transfers modeled.</li></ol>	Reliability Standard”.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<div>7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).</div> <div>8. Include existing and planned facilities.</div> <div>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</div> <div>R1-2. Corrective Plan Requirements</div> <div>When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard 051-R1-1, the Planning Authority and Transmission Planner shall:</div> <div>1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:<div>a. Including a schedule for implementation,</div><div>b. Including a discussion of expected required in-service dates of facilities,</div><div>c. Consider lead times necessary to implement plans.</div></div> <div>2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</div> <div>R1-3. Reporting Requirements</div> <div>The documentation of results of these reliability</div>	<div>I.A. M1</div> <div>Corrective Plan Requirements</div> <div>I.A. M1</div> <div>Reporting</div>	<div>6. Be performed for selected demand levels over the range of forecast system demands.</div> <div>7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).</div> <div>8. Include existing and planned facilities.</div> <div>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</div> <div>Corrective Plan Requirements</div> <div>When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall:</div> <div>1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:<div>a. Including a schedule for implementation,</div><div>b. Including a discussion of expected required in-service dates of facilities,</div><div>c. Consider lead times necessary to implement plans.</div></div> <div>2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</div> <div>Reporting Requirements</div>	<div>Changed reference to Requirement R1-1 instead of Measurement M1</div>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	assessments and corrective plans shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.	Requirements	The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.	
Section 1 Measures	<p>M1-1. The Planning Authority and Transmission Planner shall provide evidence that it provided assessments and corrective plans for the system responses per Standard 051 R1-1 and R1-2.</p> <p>M1-2. The Planning Authority and Transmission Planner shall provide evidence that it reported documentation of results of its reliability assessments and corrective plans per Standard 051 R1-3.</p>	IAM1 Items to be -- Measured	System performance under normal (no contingency) conditions.	Added words “assessments and corrective plans” to the language to make a measurable standard. Added reference to this Reliability Standard and its requirements.
Section 1 Regional Differences	None identified	None	None identified	
Section 1 Compliance Monitoring Process	<p>Annually</p> <p>Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.</p>	<p>IAM1 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Annually</p> <p>Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.</p>	
Section 1 Levels of Non Compliance	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan for the</p>	<p>IAM1</p> <p>Levels of non-compliance</p>	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan for the</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.</p>		<p>longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.</p>	
Section 2	System performance following loss of a single bulk system element	Brief Descriptions I.A.M2	System performance following loss of a single bulk system element	
Section 2 Applicability	Planning Authority and Transmission Planner.	I.A.M2 Applicable to	Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS).	
Section 2 Requirements		Standard for I.A.M2	<p>S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I (attached).</p> <p>Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.</p> <p>The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as</p>	The content of S2 is repeated and detailed more completely in the M2 measurement and therefore not used directly in translation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R2-1. Assessment Requirements</p> <p>Planning Authorities and Transmission Planners shall assess the performance of their systems in meeting the requirements of this Reliability Standard.</p> <p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category B contingencies that addresses the plan year being assessed,</li><li>4. Address any planned upgrades needed to meet the performance requirements of Category B,</li><li>5. Consider all contingencies applicable to Category B.</li></ol>	IAM2 Assessment Requirements	<p>defined in Category B of Table I (attached).</p> <p><b>Assessment Requirements</b></p> <p>Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), for example:</p> <ol style="list-style-type: none"><li>1. Transmission owners,</li><li>2. Independent system operators (ISOs),</li><li>3. Regional transmission organizations (RTOs).</li></ol> <p>Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S2.</p> <p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category B contingencies that addresses the plan year being assessed,</li><li>4. Address any planned upgrades needed to meet the performance requirements of Category B,</li><li>5. Consider all contingencies applicable to Category B.</li></ol>	Reference to Standard S2 was replaced with “this Reliability Standard”.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall:</p> <ol style="list-style-type: none"><li>Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts:<ol style="list-style-type: none"><li>The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li><li>Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li><li>Be conducted annually unless changes to system conditions do not warrant such analyses.</li><li>Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li><li>Have all projected firm transfers modeled.</li><li>Be performed and evaluated for selected demand levels over the range of forecast system demands.</li><li>Demonstrate that system performance meets Table 1 for Category B contingencies.</li></ol>	I.A.M2 System Simulation Study/Testing Methods	<p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall:</p> <ol style="list-style-type: none"><li>Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts:<ol style="list-style-type: none"><li>The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li><li>Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li><li>Be conducted annually unless changes to system conditions do not warrant such analyses.</li><li>Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li><li>Have all projected firm transfers modeled.</li><li>Be performed and evaluated for selected demand levels over the range of forecast system demands.</li><li>Demonstrate that system performance meets Table 1 for Category B contingencies.</li></ol>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<div>8. Include existing and planned facilities.</div> <div>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</div> <div>10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</div> <div>11. Include the effects of existing and planned control devices.</div> <div>12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed</div> <div>R2-2. Corrective Plan Requirements</div> <div>When system simulations indicate an inability of the systems to respond as prescribed in Requirement R2-1, Planning Authorities and Transmission Owners responsible for planning the bulk electric system shall:</div> <div>1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:<div>a. Including a schedule for implementation,</div><div>b. Including a discussion of expected required in-service dates of facilities,</div></div>	<div>I.A. M2</div> <div>Corrective</div> <div>Plan</div> <div>Requirements</div>	<div>8. Include existing and planned facilities.</div> <div>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</div> <div>10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</div> <div>11. Include the effects of existing and planned control devices.</div> <div>12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed</div> <div>Corrective Plan Requirements</div> <div>When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M2), responsible entities shall:</div> <div>1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,<div>a. Including a schedule for implementation,</div><div>b. Including a discussion of expected required in-service dates of facilities,</div><div>c. Consider lead times necessary to implement</div></div>	<div>Changed reference to Requirement R2-1 instead of Measurement M2</div>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>c. Consider lead times necessary to implement plans.</p> <p>2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</p> <p>R2-3. Reporting Requirements</p> <p>The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.</p>	I.A. M2 Reporting Requirements	<p>plans.</p> <p>2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</p> <p><b>Reporting Requirements</b></p> <p>The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.</p>	
Section 2 Measures	<p><b>M2-1</b> The Planning Authority and Transmission Planner shall provide evidence that it provided assessments and corrective plans for the system responses per Standard 051 R2-1 and R2-2.</p> <p><b>M2-2</b> The Planning Authority and Transmission Planner shall provide evidence that it reported documentation of results of its reliability assessments and corrective plans</p>	IAM2 Items to be -- Measured	Assessments supported by simulated system performance following loss of a single bulk system element.	Added words “available assessments and corrective plans” to the language to make a measurable standard. Changed reference from S2 to this Reliability Standard.
Section 2 Regional Differences	None identified	None	None identified	
Section 2 Compliance Monitoring Process	<p>Annually</p> <p>Regional Reliability Council. Each Region shall report</p>	<p>IAM2 Timeframe</p> <p>Compliance</p>	<p>Annually</p> <p>Regional Reliability Council. Each Region shall report</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	compliance and violations to NERC via the NERC Compliance Reporting Process.	Monitoring Responsibility	compliance and violations to NERC via the NERC Compliance Reporting Process.	
Section 2 Levels of Non Compliance	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan for the longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.</p>	IAM2 Levels of Non-Compliance	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.</p>	
Section 3	System performance following loss of two or more bulk system elements	Brief Descriptions I.A.M3	System performance following loss of two or more bulk system elements	
Section 3 Applicability	Planning Authority and Transmission Planner.	I.A.M3 Applicable to	Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS).	
Section 3 Requirements		Standard for  IAM3	S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category C of	The content of S3 is repeated and detailed more completely in the M3 measurement and therefore not used directly in translation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R3-1. Assessment Requirements</p> <p>Planning Authorities and Transmission Planners shall assess the performance of their systems in meeting the requirements of this Reliability Standard.</p>	<p>I.A. M3 Assessment Requirements</p>	<p>Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers maybe necessary to meet this standard.</p> <p>Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.</p> <p>The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category C of Table I (attached).</p> <p>Assessment Requirements</p> <p>Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:</p> <ol style="list-style-type: none"><li>1. Transmission owners,</li><li>2. Independent system operators (ISOs),</li><li>3. Regional transmission organizations (RTOs).</li></ol> <p>Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S3.</p> <p>To be valid <i>and compliant</i>, assessments shall:</p>	<p>Reference to Standard S3 was replaced with “this Reliability Standard”.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category C contingencies that addresses the plan year being assessed,</li><li>4. Address any planned upgrades needed to meet the performance requirements of Category C,</li><li>5. Consider all contingencies applicable to Category C.</li></ol> <p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall:</p> <ol style="list-style-type: none"><li>1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.<ol style="list-style-type: none"><li>a. The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li></ol>	I.A.M3 System Simulation Study/Testing Methods	<ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category C contingencies that addresses the plan year being assessed,</li><li>4. Address any planned upgrades needed to meet the performance requirements of Category C,</li><li>5. Consider all contingencies applicable to Category C.</li></ol> <p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall:</p> <ol style="list-style-type: none"><li>1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.<ol style="list-style-type: none"><li>a. The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li><li>2. Cover critical system conditions and study</li></ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<ol style="list-style-type: none"> <li>2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li> <li>3. Be conducted annually unless changes to system conditions do not warrant such analyses.</li> <li>4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li> <li>5. Have all projected firm transfers modeled.</li> <li>6. Be performed and evaluated for selected demand levels over the range of forecast system demands.</li> <li>7. Demonstrate that system performance meets Table 1 for Category C contingencies.</li> <li>8. Include existing and planned facilities.</li> <li>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</li> <li>10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</li> <li>11. Include the effects of existing and planned control devices.</li> <li>12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed</li> </ol>		<p>years as deemed appropriate by the responsible entity.</p> <ol style="list-style-type: none"> <li>3. Be conducted annually unless changes to system conditions do not warrant such analyses.</li> <li>4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.</li> <li>5. Have all projected firm transfers modeled.</li> <li>6. Be performed and evaluated for selected demand levels over the range of forecast system demands.</li> <li>7. Demonstrate that system performance meets Table 1 for Category C contingencies.</li> <li>8. Include existing and planned facilities.</li> <li>9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</li> <li>10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</li> <li>11. Include the effects of existing and planned control devices.</li> <li>12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for</li> </ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p><b>R3-2. Corrective Plan Requirements</b></p> <p>When system simulations indicate an inability of the systems to respond as prescribed in Requirement 3-1, Planning Authorities and Transmission Owners responsible for planning the bulk electric system shall:</p> <ol style="list-style-type: none"><li>1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:<ol style="list-style-type: none"><li>a. Including a schedule for implementation,</li><li>b. Including a discussion of expected required in-service dates of facilities,</li><li>c. Consider lead times necessary to implement plans.</li></ol></li><li>2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</li></ol>	<p><b>I.A. M3 Corrective Plan Requirements</b></p> <p><b>I.A. M3 Reporting Requirements</b></p>	<p>which planned (including maintenance) outages are performed</p> <p><b>Corrective Plan Requirements</b></p> <p>When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M3), responsible entities shall:</p> <ol style="list-style-type: none"><li>1 Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,<ol style="list-style-type: none"><li>a. Including a schedule for implementation,</li><li>b. Including a discussion of expected required in-service dates of facilities,</li><li>c. Consider lead times necessary to implement plans.</li></ol></li><li>2 For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.</li></ol> <p><b>Reporting Requirements</b></p> <p>The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability</p>	<p>Changed reference to Requirement R3-1 instead of Measurement M3</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			assessments and corrective actions to NERC.	
Section 3 Measures	<p>M3-1 The Planning Authority and Transmission Planner shall provide evidence that it provided assessments and corrective plans for the system responses per Standard 051 R3-1 and R3-2.</p> <p>M3-2 The Planning Authority and Transmission Planner shall provide evidence that it reported documentation of results of its reliability assessments and corrective plans</p>	IAM3 Items to be -- Measured	Assessments supported by simulated system performance following loss of two or more bulk system element.	Added words “available assessments and corrective plans” to the language to make a measurable standard. Changed reference from S3 to this Reliability Standard.
Section 3 Regional Differences	None identified	None	None identified	
Section 3 Compliance Monitoring Process	<p>Annually</p> <p>Regional Reliability Council.</p>	<p>IAM3 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Annually</p> <p>Regional Reliability Council.</p>	
Section 3 Levels of Non Compliance	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan for the longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.</p>	IAM3 Levels of Non- Compliance	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — N/A.</p> <p>Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.</p> <p>Level 3 — N/A</p> <p>Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 4	System performance following extreme events resulting in the loss of two or more bulk system elements	Brief Descriptions I.A.M4	System performance following extreme events resulting in the loss of two or more bulk system elements	
Section 4 Applicability	Planning Authority and Transmission Planner.	I.A.M4 Applicable to	Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS).	
Section 4 Requirements	<p>R4-1. Assessment Requirements <sup>1</sup></p> <p>Planning Authorities and Transmission Planners shall assess the performance of their systems in meeting the requirements of this Reliability Standard.</p>	<p>Standard for I.A.M4</p> <p>I.A. M4 Assessment Requirements</p>	<p>S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).</p> <p><b>Assessment Requirements</b></p> <p>Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:</p> <ol style="list-style-type: none"> <li>1. Transmission owners,</li> <li>2. Independent system operators (ISOs),</li> <li>3. Regional transmission organizations (RTOs).</li> </ol> <p>Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S4.</p>	<p>The content of S4 is repeated and detailed more completely in the M4 measurement and therefore not used directly in translation.</p> <p>Reference to Standard S4 was replaced with “this Reliability Standard”.</p>

<sup>1</sup> Corrective Plan Requirements: None required.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five),</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category D contingencies that addresses the plan year being assessed,</li><li>4. Consider all contingencies applicable to Category D.</li></ol> <p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall (as agree to by the Region) :</p> <ol style="list-style-type: none"><li>1. Be performed and evaluated only for those Category d contingencies that would produce the more severe system results or impacts.<ol style="list-style-type: none"><li>a. The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li><li>2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.</li><li>3. Be conducted annually unless changes to system</li></ol>	I.A.M4 System Simulation Study/Testing Methods	<p>To be valid <i>and compliant</i>, assessments shall:</p> <ol style="list-style-type: none"><li>1. Be made annually,</li><li>2. Be conducted for near-term (years one through five),</li><li>3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category D contingencies that addresses the plan year being assessed,</li><li>4. Consider all contingencies applicable to Category D.</li></ol> <p><b>System Simulation Study/Testing Methods</b></p> <p>System simulation studies/testing shall (as agree to by the Region) :</p> <ol style="list-style-type: none"><li>1. Be performed and evaluated only for those Category d contingencies that would produce the more severe system results or impacts.<ol style="list-style-type: none"><li>c. The rationale for the contingencies selected for evaluation shall be available as supporting information,</li><li>d. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</li></ol></li><li>2. Cover critical system conditions and study years as deemed appropriate by the</li></ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>conditions do not warrant such analyses.</p> <p>4. Have all projected firm transfers modeled.</p> <p>5. Include existing and planned facilities.</p> <p>6. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</p> <p>7. Include the effects of existing and planned protection systems, including any backup or redundant systems.</p> <p>8. Include the effects of existing and planned control devices.</p> <p>9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed</p> <p><b>R4-2. Reporting Requirements</b></p> <p>The documentation of results of these reliability assessments shall annually be provided to the entities’</p>	<p>.A. M4 Corrective Plan Requirements</p> <p>I.A. M4 Reporting Requirements</p>	<p>responsible entity.</p> <p>3. Be conducted annually unless changes to system conditions do not warrant such analyses.</p> <p>4. Have all projected firm transfers modeled.</p> <p>5. Include existing and planned facilities.</p> <p>6. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.</p> <p>7. Include the effects of existing and planned protection systems, including any backup or redundant systems.</p> <p>8. Include the effects of existing and planned control devices.</p> <p>9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed</p> <p><b>Corrective Plan Requirements</b></p> <p>None required</p> <p><b>Reporting Requirements</b></p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	respective NERC Region(s), as required by the Region.		The documentation of results of these reliability assessments shall annually be provided to the entities' respective NERC Region(s), as required by the Region.	
Section 4 Measures	<p>M4-1. The Planning Authority and Transmission Planner shall provide assessments for the system responses per Standard 051 R3-1.</p> <p>M3-2. The Planning Authority and Transmission Planner shall provide evidence that it reported documentation of results of its reliability assessments per Standard 051 R4-1.</p>	IAM4 Items to be Measured	Assessments of system performance for extreme events (more severe than in I.A.M3) resulting in loss of two or more bulk system elements.	Added words “have available assessments of” to the language to make a measurable standard. Changed reference from S4 to this Reliability Standard.
Section 4 Regional Differences	None identified	None	None identified	
Section 4 Compliance Monitoring Process	<p>Annually</p> <p>Annually</p> <p>Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.</p>	<p>IAM4 Timeframe</p> <p>Compliance-Monitoring Responsibility</p>	<p>Annually</p> <p>Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.</p>	
Section 4 Levels of Non Compliance	<p>Level 1 — A valid assessment, as defined above, for the near-term planning horizon is not available.</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — N/A</p>	<p>IAM4</p> <p>Levels of non-compliance</p>	<p>(If non-compliant at more than one Level, the highest Level applies.)</p> <p>Level 1 — A valid assessment, as defined above, for the near-term planning horizon is not available.</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — N/A</p>	No changes

**Table I. Transmission System Standards – Normal and Emergency Conditions\***

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading <sup>c</sup> Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating <sup>a</sup> (A/R)	Applicable Rating <sup>a</sup> (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Single Single Single Single	A/R A/R A/R A/R	A/R A/R A/R A/R	Yes Yes Yes Yes	No <sup>b</sup> No <sup>b</sup> No <sup>b</sup> No <sup>b</sup>	No No No No
	Single Pole Block, Normal Clearing <sup>f</sup> : 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No <sup>b</sup>	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing <sup>f</sup> : 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled <sup>d</sup> Planned/Controlled <sup>d</sup>	No No
	SLG or 3Ø Fault, with Normal Clearing <sup>f</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>f</sup> : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled <sup>d</sup>	No
	Bipolar Block, with Normal Clearing <sup>f</sup> : 4. Bipolar (dc) Line	Multiple	A/R	A/R	Yes	Planned/Controlled <sup>d</sup>	No
	Fault (non 3Ø), with Normal Clearing <sup>f</sup> : 5. Any two circuits of a multiple circuit towerline <sup>g</sup>	Multiple	A/R	A/R	Yes	Planned/Controlled <sup>d</sup>	No
	SLG Fault, with Delayed Clearing <sup>f</sup> (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled <sup>d</sup> Planned/Controlled <sup>d</sup>	No No

\* Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards

**Table I. Transmission System Standards – Normal and Emergency Conditions\***

**Table I. Transmission System Standards – Normal and Emergency Conditions\***

D <sup>e</sup> - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	<div>3Ø Fault, with Delayed Clearing<sup>f</sup> (stuck breaker or protection system failure):<div><div>1. Generator3. Transformer</div><div>2. Transmission Circuit4. Bus Section</div></div></div> <div>-----</div> <div>3Ø Fault, with Normal Clearing<sup>f</sup> :<div>5. Breaker (failure or internal fault)</div></div> <div>-----</div> <div>Other:<div><div>6. Loss of towerline with three or more circuits</div><div>7. All transmission lines on a common right-of way</div><div>8. Loss of a substation (one voltage level plus transformers)</div><div>9. Loss of a switching station (one voltage level plus transformers)</div><div>10. Loss of all generating units at a station</div><div>11. Loss of a large load or major load center</div><div>12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required</div><div>13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate</div><div>14. Impact of severe power swings or oscillations from disturbances in another Regional Council.</div></div></div>	<div>Evaluate for risks and consequences.</div> <div><div>▪ May involve substantial loss of customer demand and generation in a widespread area or areas.</div><div>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</div><div>▪ Evaluation of these events may require joint studies with neighboring systems.</div></div>
---	---	--

- a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
- c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
- d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
- e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

## **Table I. Transmission System Standards – Normal and Emergency Conditions\***

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
ID Number	052	Compliance Templates I.B.M1 I.B.M2	I. System Adequacy and Security  B. Reliability Assessment	
Title	System Adequacy and Security Reliability Assessment	Section	I. System Adequacy and Security  B. Reliability Assessment	
Purpose	To ensure that each Regional Reliability Council complies with the NERC Planning Standards and its own Regional planning criteria, NERC needs to review and assess the overall reliability (adequacy and security) of the interconnected bulk electric systems, both existing and as planned.	Introduction for I.B	Introduction  NERC, through its Planning Committee (or successor group(s)), reviews and assesses the overall reliability (adequacy and security) of the interconnected bulk electric systems, both existing and as planned, to ensure that each Region (subregion) complies with the NERC Planning Standards and its own Regional planning criteria.	First paragraph for Introduction for I.B
Effective Date	February 8, 2005	Compliance Templates I.B.M1 I.B.M2	I.B.M1 CTTF revised and BOT approved April 2, 2004  I.B.M2, introduced in Phase 1, BOT approved June 12, 2001	
Standard Applicability	Regional Reliability Councils for Sections 1 and 2	Applicable to I.B.M1 --  I.B.M2 --	Regional Reliability Councils  Regions	Changed for terminology consistency
Section 1	Regional and interregional self-assessment reliability reports.	Brief	Regional and interregional self-assessment reliability reports.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>The Regional Reliability Council’s Regional and interregional reliability assessments shall demonstrate that the performance of these systems is in compliance with NERC Reliability Standard 051 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.</p> <p>Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.</p> <p>In addition, Regional Reliability Councils shall perform special reliability assessments as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:</p> <ul style="list-style-type: none"><li>• Security assessments</li><li>• Operational assessments</li><li>• Evaluations of emergency response preparedness</li><li>• Adequacy of fuel supply and hydro conditions</li><li>• Reliability impacts of new or proposed environmental rules and regulations</li><li>• Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North</li></ul>		<p>Regional and interregional reliability assessments shall demonstrate that the performance of these systems is in compliance with NERC Standard I.A and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.</p> <p>Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.</p> <p>In addition, special reliability assessments shall also be performed as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:</p> <ul style="list-style-type: none"><li>▪ Security assessments</li><li>▪ Operational assessments</li><li>▪ Evaluations of emergency response preparedness</li><li>▪ Adequacy of fuel supply and hydro conditions</li><li>▪ Reliability impacts of new or proposed environmental rules and regulations</li><li>• Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North America.</li></ul>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	America.			
Section 1 Measure	M1-1 The Regional Reliability Council shall provide evidence that annual regional and interregional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regions or NERC.	I.B.M1 Items to be Measured	Annual Regional and interregional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments as requested by other Regions or NERC.	Added the words “were developed and provided” to the language to make a measurable standard consistent with existing levels of non-compliance.
Section 1 Regional Differences	None	None	None	
Section 1 Compliance Monitoring Process	Annually or as requested by NERC.  NERC.	I.B.M1 Timeframe  Compliance Monitoring Responsibility	Annually or as requested by NERC.  NERC.	
Section 1 Levels of Non Compliance	Level 1 — Regional, interregional, and/or special reliability assessments were provided as requested, but were incomplete.  Level 2 — N/A.  Level 3 — N/A  Level 4 — Regional, interregional, and/or special reliability assessments were not provided.	I.B.M1 Levels of Non-Compliance	Level 1 — Regional, interregional, and/or special reliability assessments were provided as requested, but were incomplete.  Level 2 — N/A.  Level 3 — N/A  Level 4 — Regional, interregional, and/or special reliability assessments were not provided.	
Section 2	Data from the Regions needed to assess reliability.	Brief Descriptions I.B.M2	Data from the Regions needed to assess reliability.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Applicability	Regional Reliability Councils	I.B.M2 Applicable to	Regions	
Section 2 Requirements	<p>R2-1. Each Regional Reliability Council shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and bulk electric system data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional Reliability Council planning criteria.</p> <p>The facility and bulk electric system data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:</p> <ol style="list-style-type: none"><li>1. Electric Demand and Net Energy for Load (actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of demand-side management)</li><li>2. Resource Adequacy and Supporting Information (Regional assessment reports, existing and planned resource data, resource availability and</li></ol>	<p>I.B.M2 Measurement M2</p>	<p>S1. The overall reliability (adequacy and security) of the Regions’ interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region’s respective Regional planning criteria.</p> <p>M2. Each Region shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and bulk electric system data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Planning Standards and the respective Regional planning criteria.</p> <p>The facility and bulk electric system data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:</p> <ol style="list-style-type: none"><li>1. Electric Demand and Net Energy for Load (actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of demand-side management)</li><li>2. Resource Adequacy and Supporting Information (Regional assessment reports, existing and planned resource data, resource availability and characteristics,</li></ol>	<p>The content of S1 is repeated and detailed more completely in the M2 measurement and therefore not used directly in translation.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>characteristics, and fuel types and requirements)</p> <p>3. Demand-Side Resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations)</p> <p>4. Supply-Side Resources and their characteristics (existing and planned generator units, ratings, performance characteristics, fuel types and availability, and real and reactive capabilities)</p> <p>5. Transmission System and supporting information (thermal, voltage, and stability limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems)</p> <p>6. System Operations and supporting information (extreme weather impacts, interchange transactions, and congestion impacts on the reliability of the interconnected bulk electric systems)</p> <p>7. Environmental and Regulatory Issues and Impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation)</p>		<p>and fuel types and requirements)</p> <p>3. Demand-Side Resources and Their Characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations)</p> <p>4. Supply-Side Resources and Their Characteristics (existing and planned generator units, ratings, performance characteristics, fuel types and availability, and real and reactive capabilities)</p> <p>5. Transmission System and Supporting Information (thermal, voltage, and stability limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems)</p> <p>6. System Operations and Supporting Information (extreme weather impacts, interchange transactions, and congestion impacts on the reliability of the interconnected bulk electric systems)</p> <p>7. Environmental and Regulatory Issues and Impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation)</p>	
Section 2 Measures	M2-1. The Regional Reliability Councils shall provide evidence that it provided Regional system data, reports, and system performance information per Standard 052 R2-1.	I.B. M2 Items to be Measured	Regional system data, reports, and system performance information.	Made into an active voice sentence

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Regional Differences	None identified	None	None identified	
Section 2 Compliance Monitoring Process	Seasonally (winter and summer), annually, or as otherwise requested.  NERC	I.B.M2 Timeframe  Compliance Monitoring Responsibility	Seasonally (winter and summer), annually, or as otherwise requested.  NERC	
Section 2 Levels of Non Compliance	Level 1 — Requested Regional system data, reports, or system performance information were incomplete.  Level 2 — N/A.  Level 3 — N/A  Level 4 — Requested Regional system data, reports, or system performance information were not provided.	I.B.M2 Levels of Non- Compliance	Level 1 — Requested Regional system data, reports, or system performance information were incomplete.  Level 2 — N/A.  Level 3 — N/A  Level 4 — Requested Regional system data, reports, or system performance information were not provided.	No changes

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
ID Number	053	Compliance Templates I.C.M1 I.C.M2	I. System Adequacy and Security  C. Facility Connection Requirements	
Title	Facility Connection Requirements	Section	I. System Adequacy and Security  C. Facility Connection Requirements	
Purpose	To avoid adverse impacts on reliability, generation and transmission owners and electricity end-users must meet facility connection and performance requirements as specified by those responsible for the reliability of the interconnected transmission systems.	Introduction for Section I.C	Introduction  All facilities involved in the generation, transmission, and use of electricity must be properly connected to the interconnected transmission systems to avoid degrading the reliability of the electric systems to which they are connected. To avoid adverse impacts on reliability, generation and transmission owners and electricity end-users must meet facility connection and performance requirements as specified by those responsible for the reliability of the interconnected transmission systems.	Introduction for I.C, last Sentence
Effective Date	February 8, 2005	Compliance Templates I.C.M1 I.C.M2	I.C.M1, introduced in Phase 1, BOT approved June 12, 2001  I.C.M2, introduced in Phase 2, BOT approved October 16, 2001	
Standard Applicability	Section 1 Transmission Owners.  Section 2 Planning Authorities, Transmission Planners,	Applicable to	I.C.M1 - Transmission owners and providers.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Generator Owners, Transmission Owners, Load Serving Entities, and Distribution Providers		<p>I.C.M2 - Entities responsible for the reliability of the interconnected transmission systems.</p> <p>Entities seeking to integrate generation, transmission, and end-users facilities into the interconnected transmission systems.</p>	
Section 1	Facility Connection Requirements	Brief Descriptions I.C.M1	Facility Connection Requirements	
Section 1 Applicability	Transmission Owner	Applicable to I.C.M1	Transmission owners and providers.	
Section 1 Requirements	<p>R1-1. The Transmission Owner shall document, maintain, and publish facility connection requirements for</p> <ul style="list-style-type: none"> <li>a. generation facilities,</li> <li>b. transmission facilities, and</li> <li>c. end-user facilities</li> </ul> <p>to ensure compliance with NERC Standards and applicable Regional, subregional, power pool, and individual</p>	<p>Standard for I.C.M1</p> <p>I.C.M1 Measure M1</p>	<p>S1. Facility connection requirements shall be documented, maintained, and published by voltage class, capacity, and other characteristics that are applicable to generation, transmission, and electricity end-user facilities which are connected to, or being planned to be connected to, the bulk interconnected transmission systems.</p> <p>M1. Transmission providers, in conjunction with transmission owners, shall document, maintain, and publish facility connection requirements for</p> <ul style="list-style-type: none"> <li>a. generation facilities,</li> <li>b. transmission facilities, and</li> <li>c. end-user facilities</li> </ul>	The content of S1 is repeated and detailed more completely in the M1 measurement and therefore not used directly in translation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>transmission owner planning criteria and facility connection requirements.</p> <p>R1-2. The Transmission Owner’s facility connection requirements shall address, but are not limited to, the following items:</p> <ol style="list-style-type: none"><li>1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.</li><li>2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.</li><li>3. Voltage level and MW and Mvar capacity or demand at point of connection.</li><li>4. Breaker duty and surge protection.</li><li>5. System protection and coordination.</li><li>6. Metering and telecommunications.</li><li>7. Grounding and safety issues.</li><li>8. Insulation and insulation coordination.</li><li>9. Voltage, reactive power, and power factor control.</li></ol>		<p>to ensure compliance with NERC Planning Standards and applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria and facility connection requirements.</p> <p>Facility connection requirements shall address, but are not limited to, the following items:</p> <ol style="list-style-type: none"><li>1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.</li><li>2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.</li><li>3. Voltage level and MW and Mvar capacity or demand at point of connection.</li><li>4. Breaker duty and surge protection.</li><li>5. System protection and coordination</li><li>6. Metering and telecommunications.</li><li>7. Grounding and safety issues.</li><li>8. Insulation and insulation coordination.</li><li>9. Voltage, reactive power, and power factor control.</li></ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>10. Power quality impacts.</p> <p>11. Equipment ratings .</p> <p>12. Synchronizing of facilities.</p> <p>13. Maintenance coordination.</p> <p>14. Operational issues (abnormal frequency and voltages).</p> <p>15. Inspection requirements for existing or new facilities.</p> <p>16. Communications and procedures during normal and emergency operating conditions.</p> <p>R1-3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission systems, the Regional Reliability Councils, and NERC on request (five business days).</p>		<p>10. Power quality impacts.</p> <p>11. Equipment ratings.</p> <p>12. Synchronizing of facilities.</p> <p>13. Maintenance coordination.</p> <p>14. Operational issues (abnormal frequency and voltages).</p> <p>15. Inspection requirements for existing or new facilities.</p> <p>16. Communications and procedures during normal and emergency operating conditions.</p> <p>Facility connection requirements shall be maintained and updated as required.</p> <p>Documentation of these requirements shall be available to the users of the transmission systems, the Regions, and NERC on request (five business days).</p>	
Section 1 Measures	<p>M1-1. The Transmission Owner shall make available for inspection evidence that it met all the requirements stated in Reliability Standard 053-R1-1 for generation facilities, transmission facilities, and end-user facilities.</p> <p>M1-2. The Transmission Owner shall make available for</p>	I.C.M1 Items to be Measured	Facility connection requirements for generation facilities, transmission facilities, and end-user facilities.	More details were added to the high level “items to be measured” so that the measures would be consistent with the levels of non-

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>inspection evidence that they it met all 16 requirements stated in Reliability Standard 053-R1-2 for generation facilities, transmission facilities, and end-user facilities.</p> <p>M1-3. The Transmission Owner shall make available for inspection evidence that it met all the requirements stated in Reliability Standard 053-R1-3.</p>			compliance and the requirements
Section 1 Regional Differences	None identified	None	None identified	
Section 1 Compliance Monitoring Process	<p>On request (five business days)</p> <p>Regions</p>	<p>I.C.M1 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (five business days)</p> <p>Regions</p>	
Section 1 Levels of Non Compliance	<p>Level 1 — Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard 053-R1-1, but the document(s) do not address all of the requirements of R1-2.</p> <p>Level 2 — Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard 053-R1-1, but the document(s) provided address all of the requirements of R1-2.</p> <p>Level 3 — Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard 053-</p>	I.C.M1 Levels of Non-Compliance	<p>Level 1 — Facility connection requirements were provided for generation, transmission, and end-user facilities, but the document(s) do not address all of the requirements.</p> <p>Level 2 — Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, but the document(s) provided address all of the requirements.</p> <p>Level 3 — Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, and the</p>	<p>Reference to Requirements R1-1 and R1-2 were added for clarity</p> <p>Reference to Requirements R1-1 and R1-2 were added for clarity</p> <p>Reference to Requirements R1-1 and R1-2 were added</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R1-1, and the document(s) provided do not address all of the requirements of R1-2.</p> <p>Level 4 — No document on facility connection requirements was provided per Reliability Standard 053-R1-3.</p>		<p>document(s) provided do not address all of the requirements</p> <p>Level 4 — No document on facility connection requirements was provided.</p>	<p>for clarity</p> <p>Reference to Requirement R1-3 was added for clarity</p>
Section 2	Coordination of plans for new generation, transmission, and end-user facilities	Brief Descriptions I.C.M2	Coordination of plans for new generation, transmission, and end-user facilities	New section title
Section 2 Applicability	Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load Serving Entity, and Distribution Provider	Applicable to I.C.M2	<p>Entities responsible for the reliability of the interconnected transmission systems.</p> <p>Entities seeking to integrate generation, transmission, and end-users facilities into the interconnected transmission systems.</p>	Incorporated Functional Model terminology
Section 2 Requirements	R2-1. The Generator Owner, Transmission Owner, Distribution Provider, or Load Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems. The assessment shall include:	<p>Standards for I.C.M2</p> <p>I.C.M2 Measure</p>	<p>S2. Generation, transmission, and electricity end-user facilities, and their modifications, shall be planned and integrated into the interconnected transmission systems in compliance with NERC Planning Standards, applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.</p> <p>M2. Those entities responsible for the reliability of the interconnected transmission systems and those entities seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their</p>	The content of S2 is repeated and detailed more completely in the M2 measurement and therefore not used directly in translation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<ol style="list-style-type: none"><li>1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.</li><li>2. Ensurance of compliance with NERC Planning Standards and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.</li><li>3. Evidence that the parties involved in the assessment have cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.</li><li>4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under Reliability Standard 051.</li><li>5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.</li></ol> <p>R2-2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load Serving Entity, and Distribution Provider shall retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and</p>		<p>respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems and to ensure compliance with NERC Planning Standards and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.</p> <p>The entities involved shall present evidence that they have cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved. Assessments shall include steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under Standard I.A.</p> <p>Documentation of these assessments shall include study assumptions, system performance, alternatives considered, and jointly coordinated recommendations. This documentation shall be retained for three years and shall be provided to the Regions and NERC on request (within 30 days).</p>	<p>Itemized the individual requirements for the assessment</p> <p>Listed last sentence as a separate requirement</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	shall provide the documentation to the Regional Reliability Councils and NERC on request (within 30 days).			
Section 2 Measures	<p>M2-1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load Serving Entity, and Distribution Provider’s documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard 053-R2-1.</p> <p>M2-2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load Serving Entity, and Distribution Provider shall have evidence its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard 053- R2-2.</p>	I.C.M2 Items to be Measured	Assessment of the reliability impacts of new facilities.	Reworded measures for consistency with the requirements and levels of non-compliance
Section 2 Regional Differences	None		None	
Section 2 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>Regions</p>	<p>I.C.M2 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>Regions</p>	
Section 2 Levels of Non Compliance	Level 1 — Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of R2-1.	I.C.M2 Levels of Non-Compliance	Level 1 — Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Measurement M2.	Replaced reference to M1 with R2-1

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Level 2 — Not applicable. Level 3 — Not applicable. Level 4 — Assessments of the impacts of new facilities were not provided.		Level 2 — Not applicable. Level 3 — Not applicable. Level 4 — Assessments of the impacts of new facilities were not provided.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	054	Compliance Templates I.E.1.M1 I.E.1.M3 I.E.1.M4	I. System Adequacy and Security E. Transfer Capability 1. Total and Available Transfer Capabilities	
Title	Documentation and Review of Available Transfer Capability/Total Transfer Capability Methodologies and Calculations	Section	I. System Adequacy and Security E. Transfer Capability 1. Total and Available Transfer Capabilities	
Purpose	To promote the consistent and uniform application of transfer capability calculations among transmission system users, the Regional Reliability Councils shall develop methodologies for calculating Total Transfer Capability and Available Transfer Capability that comply with NERC definitions for Total Transfer Capability and Available Transfer Capability, the NERC Reliability Standards, and applicable Regional Reliability Council criteria. Methodologies and resulting values shall be made available to all participants of the electricity market. (To ensure that methodologies and resulting values are available to all participants in the electricity market.)			Language paraphrased from the original Planning Standard language of S1.
Effective Date	February 8, 2005	Approval Dates	NERC BOT approval on February 20, 2002 for all three measures (Phase 2B)	
Standard Applicability	Regional Reliability Council (Certain systems that are not required to post Available Transfer Capability values are exempt from this Standard.)	Standard Applicable to	Regions	
Section 1	Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies	I.E.1.M1 Brief Description	Documentation and Content of Each Regional TTC and ATC methodology.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>provider’s system, are included.</p> <p>c. Account for the ultimate points of power injection (sources) and power extraction (sinks) in Total Transfer Capability and Available Transfer Capability calculations.</p> <p>d. Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)</p> <p>e. Require that Total Transfer Capability and Available Transfer Capability values and posting within the current week be determined at least once per day, that daily Total Transfer Capability and Available Transfer Capability values and postings for day 8 through the first month be determined at least once per week, and that monthly Total Transfer Capability and Available Transfer Capability values and postings for months 2 through 13 be determined at least once per month.</p> <p>f. Indicate the treatment and level of customer demands, including interruptible demands.</p> <p>g. Specify how system conditions, limiting facilities,</p>		<p>outside the transmission provider’s system, are included.</p> <p>c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.</p> <p>d) Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)</p> <p>e) Require that TTC and ATC values and posting within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.</p> <p>f) Indicate the treatment and level of customer demands, including interruptible demands.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of Total Transfer Capability and Available Transfer Capability values are shared and used within the Region Reliability Council and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability Councils. In addition, specify how this information is to be used to determine Total Transfer Capability and Available Transfer Capability values. If some data is not used, provide an explanation.</p> <p>h. Describe how the assumptions for and the calculations of Total Transfer Capability and Available Transfer Capability values change over different time (such as hourly, daily, and monthly) horizons.</p> <p>i. Describe the Regional Reliability Council’s practice on the netting of transmission reservations for purposes of Total Transfer Capability and Available Transfer Capability determination.</p> <p>R1-2. The Regional Reliability Council shall make the most recent version of the documentation of its Total Transfer Capability and Available Transfer Capability methodology available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p>		<p>g) Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.</p> <p>h) Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.</p> <p>i) Describe the Region’s practice on the netting of transmission reservations for purposes of TTC and ATC determination.</p> <p>Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.</p> <p>The most recent version of the documentation of each Region’s TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			market.	
Section 1 Measures	<p>M1-1. The Regional Reliability Council shall provide evidence that its most recent Total Transfer Capability and Available Transfer Capability methodology documentation meets Reliability Standard 054-R1-1.</p> <p>M1-2 The Regional Reliability Council shall provide evidence that its Total Transfer Capability and Available Transfer Capability methodology is available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p>	I.E.1.M1 Items to be Measured	Development and documentation of each Region's TTC and ATC methodology and the completeness of the content of each Regional TTC and ATC methodology.	
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p>Available on a website accessible by NERC, the Regions, and transmission users.</p> <p>NERC</p>	<p>I.E.1.M1 Timeframe</p> <p>I.E.1.M1 Compliance Monitoring Responsibility</p>	<p>Available on a website accessible by NERC, the Regions, and transmission users.</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - The Regional Reliability Council's documented Total Transfer Capability and Available Transfer Capability methodology does not address one or two of the nine items required for documentation under Reliability Standard 054-R1-1.</p> <p>Level 2 - N/A</p>	<p>I.E.1.M1</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - The Region's documented TTC and ATC methodology does not address one or two of the nine requirements for such documentation as listed above under Measurement M1.</p> <p>Level 2 - N/A</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 - N/A</p> <p>Level 4 - The Regional Reliability Council’s documented Total Transfer Capability and Available Transfer Capability methodology does not address three or more of the nine items required for documentation under Reliability Standard 054-R1-1 or the Regional Reliability Council does not have a documented Total Transfer Capability and Available Transfer Capability methodology available on a web site in accordance with Reliability Standard 054-R1-2.</p>		<p>Level 3 - N/A</p> <p>Level 4 - The Region’s documented TTC and ATC methodology does not address three or more of the nine requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented TTC and ATC methodology.</p>	
Section 2	Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability calculations and results	I.E.1.M3 Brief Description	Review of transmission provider TTC and ATC calculation and resulting values for compliance with the Regional TTC and ATC methodology.	
Section 2 Requirements	<p>R2-1. Each Regional Reliability Council, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the Total Transfer Capability and Available Transfer Capability calculations and resulting values of member Transmission Service Providers comply with the Regional Total Transfer Capability and Available Transfer Capability methodology and applicable Regional criteria.</p> <p>R2-2. Each Regional Reliability Council shall document the results of its periodic reviews of Total Transfer Capability</p>	<p>I.E.1.M3 Standard</p> <p>I.E.1.M3 Measurement</p>	<p>S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.</p> <p>Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.</p> <p>M3 . Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>and Available Transfer Capability.</p> <p>R2-3. The Regional Reliability Council shall provide the results of its most current reviews of Total Transfer Capability and Available Transfer Capability to NERC on request (within 30 days).</p>		<p>member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days).</p>	
Section 2 Measures	<p>M2-1. The Regional Reliability Council’s written procedure for the performance of periodic reviews of Regional Total Transfer Capability and Available Transfer Capability calculations shall comply with Reliability Standard 054-R2-1.</p> <p>. M2-2 The Regional Reliability Council shall have evidence it provided documentation of the results of its periodic reviews of Total Transfer Capability and Available Transfer Capability to NERC within 30 days.</p>	I.E.1.M3 Items to be Measured	Transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.	
Section 2 Regional Differences	None identified.		None identified.	
Section 2 Compliance Monitoring Process	<p>Procedure on Request (within 30 days)</p> <p>Documentation provided to NERC on request (within 30 days).</p> <p>NERC</p>	<p>I.E.1.M3 Timeframe</p> <p>I.E.1.M3 Compliance Monitoring Responsibility</p>	<p>Procedure on Request (within 30 days)</p> <p>Documentation of results of Regional reviews on request (within 30 days)</p> <p>NERC</p>	
Section 2 Levels of Non	Level 1 - N/A.	I.E.1.M3 Levels of Non-	Level 1 - N/A.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Compliance	<p>Level 2 - The Regional Reliability Council did not perform a review of all Transmission Service Providers within its Region for consistency with its Total Transfer Capability and Available Transfer Capability methodology on an annual basis.</p> <p>Level 3 - N/A.</p> <p>Level 4 - The Regional Reliability Council does not have a procedure for performing a Total Transfer Capability and Available Transfer Capability methodology consistency review of all Transmission Service Providers within its Regional Reliability Council, or has not performed any such reviews on an annual basis.</p>	Compliance	<p>Level 2 - The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TTC and ATC methodology, as documented per Measurement I.E.1. S1, M1, on an annual basis.</p> <p>Level 3 - N/A.</p> <p>Level 4 - The Region does not have a procedure for performing a TTC and ATC methodology consistency review of all transmission providers within its Region, or has not performed any such reviews on an annual basis.</p>	
Section 3	Regional procedure for input on Total Transfer Capability and Available Transfer Capability methodologies and values.	I.E.1.M4 Brief Description	Regional procedure for input on TTC and ATC methodologies and values.	
Section 3 Requirements	R3-1. Each Regional Reliability Council, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the Total Transfer Capability and Available Transfer Capability methodology and values of	<p>I.E.1.M4 Standard</p> <p>I.E.1.M4</p>	<p>S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.</p> <p>Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.</p> <p>M4 . Each Region, in conjunction with its members, shall develop and document a procedure on how</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Council’s procedure shall specify the following:</p> <ol style="list-style-type: none"> <li>The name, telephone number and email address of a contact person to whom concerns are to be addressed.</li> <li>The amount of time it will take for a response.</li> <li>The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)</li> <li>What recourse a customer has if the response is deemed unsatisfactory.</li> </ol> <p>R3-2. The Regional Reliability Council shall post on a web site that is accessible by the Regions, NERC, and the transmission users in the electricity market, its procedure which addresses receiving and addressing concerns about the Total Transfer Capability and Available Transfer Capability methodology and Total Transfer Capability and Available Transfer Capability values of member Transmission Service Providers</p>	Measurement	<p>transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market. (S1)</p> <p>Each Region’s procedure shall specify (S1):</p> <ol style="list-style-type: none"> <li>The name, telephone number and email address of a contact person to whom concerns are to be addressed.</li> <li>The amount of time it will take for a response.</li> <li>The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)</li> <li>What recourse a customer has if the response is deemed unsatisfactory.</li> </ol>	
Section 3 Measures	<p>M3-1 The Regional Reliability Council shall have evidence that its procedure for receiving input for Available Transfer Capability and Total Transfer Capability methodologies and values meets Reliability Standard 054-R3-1.</p> <p>M3-2 The Regional Reliability Council shall have evidence that its procedure for receiving input for Available</p>	I.E.M4 Items to be Measured	Regional procedure for receiving and addressing transmission user concerns on the TTC and ATC methodology and TTC and ATC values of member transmission providers.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Transfer Capability and Total Transfer Capability methodologies and values is available on a web site accessible by the Regions, NERC, and transmission users.			
Section 3 Regional Differences	None		None	
Section 3 Compliance Monitoring Process	Procedure available on a web site accessible by the Regions, NERC, and transmission users.  NERC	I.E.1.M4 Timeframe  I.E.1.M4 Compliance Monitoring Responsibility	Procedure available on a web site accessible by the Regions, NERC, and transmission users.  NERC	
Section 3 Levels of Non Compliance	Level 1 - N/A.  Level 2 - The Regional Reliability Council does not have a procedure available on an accessible web site, or the procedure does not incorporate all required elements of Reliability Standard 054-R3-1.  Level 3 - N/A.  Level 4 - The Regional Reliability Council has no procedure available.	I.E.1.M4  Levels of Non-Compliance	Level 1 - N/A.  Level 2 - The Region does not have a procedure available on an accessible web site, or the procedure does not provide the information necessary to complete the submittal of a comment, have it processed by the Region, and have an answer provided as indicated in the procedure.  Level 3 - N/A.  Level 4 - The Region has no procedure available.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	055	Compliance Templates I.E.2.M1 I.E.2.M3 I.E.2.M4 I.E.2.M5	I. System Adequacy and Security E. Transfer Capability 2. Transfer Capabilities Margins	
Title	Documentation and Review of Capacity Benefit Margin Methodologies and Calculations	Section	I. System Adequacy and Security E. Transfer Capability 2. Transfer Capabilities Margins	
Purpose	To promote the consistent and uniform application of transfer capability margin calculations among transmission system users, by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for Capacity Benefit Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Capacity Benefit Margin methodologies and the resulting Capacity Benefit Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-Regional transactions.			Purpose was paraphrased from the Standard S1, below.
Effective Date	February 8, 2005	Approval dates	February 20, 2002	Approved by the NERC Board of Trustees in February 2002. Field-tested during Phase 2b implementation.
Applicability	Regional Reliability Council	Applicable to	Regions	
Section 1	Documentation of Regional Reliability Council Capacity Benefit	I.E.2.M1 Brief	Documentation and content of each Regional Capacity Benefit Margin methodology	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>units within the Transmission Service Provider’s system.</p> <p>d) Require that Capacity Benefit Margin be preserved only on the Transmission Service Provider’s system where the Load-Serving Entity’s load is located (i.e., Capacity Benefit Margin is an import quantity only).</p> <p>e) Describe the inclusion or exclusion rationale for generation resources of each Load Serving Entity including those generation resources not directly connected to the transmission provider’s system but serving Load Serving Entity loads connected to the Transmission Service Provider’s system.</p> <p>f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider’s system but not obligated to serve native/network load connected to the Transmission Service Provider’s system.</p> <p>g) Describe the formal process and rationale for the Regional Reliability Council to grant any variances to individual transmission providers from the Regional Reliability Council’s Capacity Benefit Margin methodology.</p> <p>h) Specify the relationship of Capacity Benefit Margin to the generation reliability requirement and the allocation of the Capacity Benefit Margin</p>		<p>in a transmission provider’s CBM calculation be restricted to those units within the transmission provider’s system.</p> <p>d) Require that CBM be preserved only on the transmission provider’s system where the load-serving entity’s load is located (i.e., CBM is an import quantity only).</p> <p>e) Describe the inclusion or exclusion rationale for generation resources of each LSE including those generation resources not directly connected to the transmission provider’s system but serving LSE loads connected to the transmission provider’s system.</p> <p>f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider’s system but not obligated to serve native/network load connected to the transmission provider’s system.</p> <p>g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.</p> <p>h) Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>values to the appropriate transmission facilities. The sum of the Capacity Benefit Margin values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.</p> <p>i) Describe the inclusion or exclusion rationale for the loads of each Load Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).</p> <p>j) Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the Capacity Benefit Margin values.</p> <p>R1-2. The Regional Reliability Council shall make the most recent version of the documentation of its Capacity Benefit Margin methodology available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p>		<p>values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.</p> <p>i) Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).</p> <p>j) Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.</p> <p>Each Regional CBM methodology shall address each of the items listed above and shall explain its use, if any, in determining CBM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining CBM values.</p> <p>The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.</p>	
Section 1 Measures	M1-1. The Regional Reliability Council's most recent Capacity Benefit Margin methodology documentation	I.E.2.M1 Items to be	Development and documentation of each Region's Capability Benefit Margin methodology and the	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>shall meet Reliability Standard 055-R1-1.</p> <p>M1-2 The Regional Reliability Council’s Capacity Benefit Margin methodology shall be available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p>	Measured	completeness of the content of each Regional CBM methodology.	
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p>Available on a web site accessible by NERC, the Regional Reliability Councils, and transmission users.</p> <p>NERC</p>	<p>I.E.2.M1 Timeframe</p> <p>I.E.2.M1 Compliance Monitoring Responsibility</p>	<p>Available on a web site accessible by NERC, the Regions, and transmission users.</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - The Regional Reliability Council’s documented Capacity Benefit Margin methodology does not address one or two of the ten items required for documentation under Reliability Standard 055-R1-1.</p> <p>Level 2 - N/A</p> <p>Level 3 - N/A</p> <p>Level 4 - The Regional Reliability Council’s documented Capacity Benefit Margin methodology does not address three or more of the ten items required for documentation under Reliability Standard 055-R1-1, or the Regional Reliability Council does not have a documented Capacity Benefit Margin</p>	<p>I.E.2.M1</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - The Region’s documented CBM methodology does not address one or two of the ten requirements for such documentation as listed above under Measurement M1.</p> <p>Level 2 - N/A.</p> <p>Level 3 - N/A.</p> <p>Level 4 - The Region’s documented CBM methodology does not address three or more of the ten requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented CBM methodology.</p>	





Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>verification review shall be implemented.</p> <p>b. Require review of the process by which Capacity Benefit Margin values are updated, and their frequency of update, to ensure that the most current Capacity Benefit Margin values are available to transmission users.</p> <p>c. Require review of the consistency of the Transmission Service Provider’s Capacity Benefit Margin components with its published planning criteria. A Capacity Benefit Margin value is considered consistent with published planning criteria if the same components that comprise Capacity Benefit Margin are also addressed in the planning criteria. The methodology used to determine and apply Capacity Benefit Margin does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.</p> <p>d. Require Capacity Benefit Margin values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.</p>		<p>a) Indicate the frequency under which the verification review shall be implemented.</p> <p>b) Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.</p> <p>c) Require review of the consistency of the transmission provider’s CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.</p> <p>d) Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R2-2. Each Regional Reliability Council shall document the results of its periodic Capacity Benefit Margin reviews and shall make the results available to NERC on request (within 30 days).</p> <p>R2-3 The Regional Reliability Council shall provide documentation of the results of the most current implementation of its Capacity Benefit Margin procedure to NERC on request (within 30 days).</p>		<p>in the electricity markets.</p> <p>The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).</p>	
Section 2 Measures	<p>M2-1. The Regional Reliability Council’s written procedure for the performance of periodic reviews of Regional Capacity Benefit Margin calculations shall comply with Reliability Standard 055-R2-1.</p> <p><b>M2-2</b> The Regional Reliability Council shall have documentation of the results of its periodic reviews of Capacity Benefit Margin calculations, in accordance with Reliability Standard 055-R2-1 and R2-2.</p> <p>M2-3 The Regional Reliability Council shall have evidence it provided documentation of the Capacity Benefit Margin procedure and the results of the most current implementation of the procedure to NERC as requested (within 30 days).</p>	I.E.2.M3 Items to be Measured	Regional procedure and its implementation for verifying member transmission provider CBM values.	
Section 2 Regional Differences	None identified.		None identified.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Compliance Monitoring Process	<p>The documentation of the Regional Reliability Council’s Capacity Benefit Margin procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).</p> <p>NERC</p>	<p>I.E.2.M3 Timeframe</p> <p>I.E.2.M3 Compliance Monitoring Responsibility</p>	<p>The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).</p> <p>NERC</p>	
Section 2 Levels of Non Compliance	<p>Level 1 - N/A.</p> <p>Level 2 - The Regional Reliability Council did not perform a review of all Transmission Service Providers within its Regional Reliability Council for consistency with the Regional Reliability Council’s Capacity Benefit Margin methodology on an annual basis.</p> <p>Level 3 - N/A.</p> <p>Level 4 - The Regional Reliability Council does not have a procedure for performing a Capacity Benefit Margin methodology consistency review of all Transmission Service Providers within its Regional Reliability Council, or has not performed any such reviews on an annual basis.</p>	<p>I.E.2.M3 Levels of Non- Compliance</p>	<p>Level 1 - N/A.</p> <p>Level 2 - The Region did not perform a review of all transmission providers within its Region for consistency with the Regional CBM methodology, as documented per Measurement I.E.2 S1, M1, on an annual basis.</p> <p>Level 3 - N/A.</p> <p>Level 4 - The Region does not have a procedure for performing a CBM methodology consistency review of all transmission providers within its Region, or has not performed any such review on an annual basis.</p>	
Section 3	Procedures for the use of Capacity Benefit Margin values	I.E.2.M4 Brief Description	Procedures for the use of Capacity Benefit Margin values	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	NERC, and the transmission users in the electricity market.		<p>b) Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.</p> <p>c) Describe the conditions under which CBM may be available as non-firm transmission service. (S1)</p> <p>The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.</p>	
Section 3 Measures	<p><b>M3-1</b> The Transmission Service Provider’s procedure for the use of Capacity Benefit Margin (scheduling of energy against a Capacity Benefit Margin preservation) shall meet Reliability Standard 055-R3-1.</p> <p><b>M3-2</b> The Transmission Service Provider’s procedure for the use of Capacity Benefit Margin (scheduling of energy against a Capacity Benefit Margin preservation) shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.</p>	I.E.2.M4 Items to be Measured	Documentation of CBM use procedures.	
Section 3 Regional Differences	None identified.		None identified.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Compliance Monitoring Process	Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.  Regional Reliability Council	I.E.2.M4 Timeframe  I.E.2.M4 Compliance Monitoring Responsibility	Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.  Region	
Section 3 Levels of Non Compliance	Level 1 - The Transmission Service Provider’s Capacity Benefit Margin use procedure is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard 055-R3-1.  Level 2 - N/A.  Level 3 - N/A.  Level 4 - The Transmission Service Provider’s Capacity Benefit Margin use procedure addresses one or none of the three requirements as listed above under Reliability Standard 055-R3-1, or is not available.	I.E.2.M4  Levels of Non- Compliance	Level 1 - The transmission provider’s CBM use procedure is available and addresses only two of the three requirements for such documentation as listed above under Measurement M4.  Level 2 - N/A.  Level 3 - N/A.  Level 4 - The transmission provider’s CBM use procedure addresses one or none of the three requirements as listed above under Measurement M4, or is not available.	
Section 4	Documentation of the use of Capacity Benefit Margin	I.E.2.M5 Brief Description	Documentation of the use of Capacity Benefit Margin	
Section 4 Applicability	Transmission Service Provider	I.E.2.M5 Applicable to	Transmission Provider	
Section 4 Requirements		I.E.2.M5 Standard	S1     Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R4-1. Each Transmission Service Provider that uses Capacity Benefit Margin shall report the use of Capacity Benefit Margin by the Load Serving Entities' loads on its system, except for Capacity Benefit Margin sales as non-firm transmission service. (The use of Capacity Benefit Margin shall be consistent with the Transmission Service Provider's Capacity Benefit Margin use procedures.)</p> <p>R4-2. The Transmission Service Provider shall post the following three items within 15 days after the use of Capacity Benefit Margin for emergency purposes, on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.</p> <ol style="list-style-type: none"><li>1. Circumstances</li><li>2. Duration</li><li>3. Amount of Capacity Benefit Margin used</li></ol>	I.E.2.M5 Measurements	<p>with the above NERC definition for CBM and applicable Regional criteria.</p> <p>Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.</p> <p>M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)</p> <p>Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.</p> <p>The use of CBM also shall be consistent with the transmission provider's CBM use procedures.</p> <p>The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 4 Measures	<p>M4-1. The Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that energy was scheduled against a Capacity Benefit Margin preservation (for purposes other than non-firm transmission sales) on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.</p> <p>.M4-2If the Transmission Service Provider had energy scheduled against a Capacity Benefit Margin preservation (for purposes other than non-firm transmission sales) the Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that includes the elements required by Reliability Standard 055-R4-2.</p>	I.E.2.M5 Items to be Measured	After the fact disclosure that energy was scheduled against a CBM preservation (for purposes other than non-firm transmission sales).	
Section 4 Regional Differences	None identified.		None identified.	
Section 4 Compliance Monitoring Process	<p>Within 15 days of the use of Capacity Benefit Margin (excluding non-firm sales).</p> <p>Regional Reliability Council</p>	<p>I.E.2.M5 Timeframe</p> <p>I.E.2.M5 Compliance Monitoring Responsibility</p>	<p>Within 15 days of the use of CBM (excluding non-firm sales).</p> <p>Region</p>	
Section 4 Levels of Non Compliance	<p>Level 1 - N/A.</p> <p>Level 2 - Information pertaining to the use of Capacity Benefit Margin during an energy emergency was provided, but was not made available on a web site accessible by the Regional Reliability Councils, NERC, and transmission users in the</p>	I.E.2.M5 Levels of Non-Compliance	<p>Level 1 - N/A.</p> <p>Level 2 - Information pertaining to the use of CBM during an energy emergency was provided, but was not made available on a web site accessible by the Regions, NERC, and transmission users in the electricity market, or meets only</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>electricity market, or meets only two of the three requirements as listed in Reliability Standard 055-R4-2.</p> <p>Level 3 - N/A.</p> <p>Level 4 - After the use of Capacity Benefit Margin (excluding non-firm sales), information pertaining to the use of Capacity Benefit Margin was provided but meets one or none of the three requirements as listed above under Reliability Standard 055-R2 or no information was provided.</p>		<p>two of the three requirements as listed above under Measurement M5.</p> <p>Level 3 - N/A.</p> <p>Level 4 -After the use of CBM (excluding non-firm sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Measurement M5, or no information was provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	056	Compliance Templates I.E.2.M6 I.E.2.M8	I. System Adequacy and Security E. Transfer Capability 2. Transfer Capabilities Margins	
Title	Documentation and Review of Transmission Reliability Margin Methodologies and Calculations	Section	I. System Adequacy and Security E. Transfer Capability 2. Transfer Capabilities Margins	
Purpose	To promote the consistent and uniform application of transfer capability margin calculations among transmission system users, by developing methodologies for calculating Transmission Reliability Margin. This methodology shall comply with NERC definitions for Transmission Reliability Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Transmission Reliability Margin methodologies and the resulting Transmission Reliability Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-Regional transactions.			Purpose was paraphrased from the Standard S2, below.
Effective Date	February 8, 2005	Approval dates	February 20, 2002 Approved by the NERC Board of Trustees in February 2002. Field-tested during Phase 2b implementation.	
Standard Applicability	Regional Reliability Council	Applicable to	Regions	
Section 1	Documentation and content of each Regional Transmission Reliability Margin methodology.	I.E.2.M6 Brief Description	Documentation and content of each Regional Transmission Reliability Margin methodology.	
Section 1	Regional Reliability Council	I.E.2.M6 Applicable to	Region	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Applicability				
Section 1 Requirements	<p>R1-1. Each Regional Reliability Council, in conjunction with its members, shall develop and document a Regional Transmission Reliability Margin methodology. The Region’s Transmission Reliability Margin methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining Transmission Reliability Margin values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining Transmission Reliability Margin values.</p> <ol style="list-style-type: none"> <li>1. Specify the update frequency of Transmission Reliability Margin calculations.</li> <li>2. Specify how Transmission Reliability Margin values are incorporated into Available Transfer Capability calculations.</li> <li>3. Specify the uncertainties accounted for in Transmission Reliability Margin and the methods used to determine their impacts on the Transmission Reliability Margin values.</li> </ol> <p>The following components of uncertainty, if applied, shall be accounted for solely in Transmission Reliability Margin and not Capacity Benefit Margin: aggregate load forecast error (not included in determining generation reliability</p>	I.E.2.M6 Requirements	<p>S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.</p> <p>Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.</p> <p>M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)</p> <p>Each Region’s TRM methodology shall (S2):</p> <ol style="list-style-type: none"> <li>a) Specify the update frequency of TRM calculations.</li> <li>b) Specify how TRM values are incorporated into ATC calculations.</li> <li>c) Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values.</li> </ol> <p>The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).</p> <p>Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in Transmission Reliability Margin calculations.</p> <p>4. Describe the conditions, if any, under which Transmission Reliability Margin may be available to the market as non-firm transmission service.</p> <p>5. Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional Transmission Reliability Margin methodology.</p> <p>R1-2 The Regional Reliability Council shall make most recent version of the documentation of its Transmission Reliability Margin methodology available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p>		<p>determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).</p> <p>Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.</p> <p>d) Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.</p> <p>e) Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.</p> <p>Each Regional TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.</p> <p>The most recent version of the documentation of each</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			Region's TRM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.	
Section 1 Measures	<p>M1-1. The Regional Reliability Council's most recent version of the documentation of its Transmission Reliability Margin methodology is available on a web site accessible by NERC, the Regional Reliability Councils, and the transmission users in the electricity market.</p> <p>M1-2. The Regional Reliability Council's most recent version of the documentation of its Transmission Reliability Margin contains all items in Reliability Standard 056-R1-1.</p>	I.E.2.M6 Items to be Measured	Development and documentation of each Region's Transmission Reliability Margin methodology and the completeness of the content of each Regional TRM methodology.	
Section 1 Regional Differences	None		None	
Section 1 Compliance Monitoring Process	<p>Each Regional Reliability Council shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p> <p>NERC</p>	<p>I.E.2.M6 Timeframe</p> <p>I.E.2.M6 Compliance Monitoring Responsibility</p>	<p>Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - The Regional Reliability Council's documented Total Transfer Capability and Available Transfer Capability methodology does not address one of the five items required for documentation under Reliability Standard 056-R1-1.</p> <p>Level 2 - N/A</p> <p>Level 3 - N/A</p>	<p>I.E.2.M6</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - The Region's document TRM methodology does not address one of the five requirements for each documentation as listed above under Measurement M6.</p> <p>Level 2 - N/A.</p> <p>Level 3 - N/A.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 4 - The Regional Reliability Council’s documented Total Transfer Capability and Available Transfer Capability methodology does not address two or more of the five items required for documentation under Reliability Standard 056-R1-1.</p> <p style="text-align: center;">Or</p> <p>the Region does not have a documented Transmission Reliability Margin methodology.</p>		<p>Level 4 - The Region’s documented TRM methodology does not address two or more of the five requirements for such documentation as listed above under Measurement M6, or the Region does not have a documented TRM methodology.</p>	
Section 2	Procedure for verifying Transmission Reliability Margin values.	I.E.2.M8 Brief Description	Procedure for verifying Transmission Reliability Margin values.	
Section 2 Applicability	Regional Reliability Council	I.E.2.M8 Applicable to	Regions	
Section 2 Requirements	<p>R2-1. Each Regional Reliability Council, shall develop and implement a procedure to review Transmission Reliability Margin calculations and resulting values of member transmission providers to ensure they comply with the Regional Transmission Reliability Margin methodology, and are periodically updated and</p>	<p>I.E.2.M8 Standard</p> <p>I.E.2.M8 Measures</p>	<p>S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.</p> <p>Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.</p> <p>M3 . Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>available to transmission users.</p> <p>This procedure shall include the following four required elements:</p> <ul style="list-style-type: none"> <li>a) Indicate the frequency under which the verification review shall be implemented.</li> <li>b) Require review of the process by which Transmission Reliability Margin values are updated, and their frequency of update, to ensure that the most current Transmission Reliability Margin values are available to transmission users.</li> <li>c) Require review of the consistency of the transmission provider’s Transmission Reliability Margin components with its published planning criteria. A Transmission Reliability Margin value is considered consistent with published planning criteria if the same components that comprise Transmission Reliability Margin are also addressed in the planning criteria. The methodology used to determine and apply Transmission Reliability Margin does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that Available Transfer Capability determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous</li> </ul>		<p>periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)</p> <p>This Regional procedure shall:</p> <ul style="list-style-type: none"> <li>a) Indicate the frequency under which the verification review shall be implemented.</li> <li>b) Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.</li> <li>c) Require review of the consistency of the transmission provider’s TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics</li> </ul>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>planning process.</p> <p>d). Require Transmission Reliability Margin values to be periodically updated (at least prior to each season - winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Councils, NERC, and transmission users in the electricity market.</p> <p>R2-2. Documentation of the Regional Reliability Council's Transmission Reliability Margin procedure shall be available to NERC on request (within 30 days).</p> <p>R2-3. Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).</p>		<p>employed in the more rigorous planning process.</p> <p>d) Require TRM values to be periodically updated (at least prior to each season winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.</p> <p>The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).</p>	
Section 2 Measures	<p>M2-1. The Regional Reliability Council shall have evidence it provided to NERC upon request (within 30 days) a copy of the written procedure developed for the performance of periodic reviews of Regional Transmission Reliability Margin calculations.</p> <p>M2-2. The Regional Reliability Council shall have evidence it provided to NERC on request (within 30 days) documentation of the results of the most current implementation of the procedure.</p>	I.E.2.M8 Items to be Measured	Regional procedure and its implementation for verifying member transmission provider TRM values.	
Section 2 Regional Differences	None identified.		None identified.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Compliance Monitoring Process	Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.  NERC	I.E.2.M8 Timeframe  I.E.2.M8 Compliance Monitoring Responsibility	Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.  NERC	
Section 2 Levels of Non Compliance	Level 1 - N/A.  Level 2 - The Regional Reliability Council did not perform a review of all Transmission Service Providers within its Regional Reliability Council for consistency with its Transmission Reliability Margin methodology on an annual basis.  Level 3 - N/A.  Level 4 - The Regional Reliability Council does not have a procedure for performing a Transmission Reliability Margin methodology consistency review of all transmission providers within its Region, or has not performed any such reviews on an annual basis.	I.E.2.M8 Levels of Non- Compliance	Level 1 - N/A.  Level 2 - The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TRM methodology, as documented per Measurement I.E.2 S2, M8, on an annual basis.  Level 3 - N/A.  Level 4 - The Region does not have a procedure for performing a TRM methodology consistency review of all transmission providers in its Region, or has not performed any such reviews on an annual basis.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	057	Compliance Template I.F.M1 I.F.M2 I.F.M3 I.F.M4 I.F.M5	I. System Adequacy and Security  F. Disturbance Monitoring	
Title	Requirements for the Installation and Reporting of Disturbance Monitoring Equipment	Section	I. System Adequacy and Security  F. Disturbance Monitoring	
Purpose	To ensure that disturbance monitoring equipment is installed in a uniform manner to facilitate development of models and analyses of events.			Adopted from brief description in original Planning Standards.
Effective Date	February 8, 2005	Approval Dates	I.F.M1 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 I.F.M2 - Approved for field testing in Phase III October 20, 2003 I.F.M3 - Approved for field testing in Phase III October 9, 2000 I.F.M4 - Approved for field testing in Phase III October 9, 2000 I.F.M5 - Approved by Engineering Committee July 14, 1998	
Standard Applicability	Section 1: Regional Reliability Council  Section 2: Transmission Owner, Generator Owner  Sections 3 and 4: Transmission Owner, Generator Owner, Transmission Operator, Generator Operator as applicable.	Applicable to:	M1 and M3 Regions.  M2, M4 Regional members, generation owners, and transmission owners  M5, Planning Authority	Incorporated Functional Model (Version 2) terminology.



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>equipment</p> <p>a. Voltage</p> <p>b. Current</p> <p>c. Frequency</p> <p>d. MW and/or Mvar, as appropriate</p> <p>4. Data retention capabilities (e.g., length of time data is to be available for retrieval)</p> <p>5. Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea)</p> <p>6. Installation requirements:</p> <p>a. Substations</p> <p>b. Transmission lines</p> <p>7. Responsibility for maintenance and testing.</p> <p>8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.</p> <p>R1-2. The Regional Reliability Council’s requirements for the installation of disturbance monitoring equipment shall be provided to other Regional Reliability Councils and NERC on request (30 days).</p>		<ul style="list-style-type: none"><li>• data format requirements</li><li>• event triggering requirements</li></ul> <p>3. Monitoring, recording, and reporting capabilities of the equipment</p> <ul style="list-style-type: none"><li>• voltage</li><li>• current</li><li>• frequency</li><li>• MW and/or Mvar, as appropriate</li></ul> <p>4. Data retention capabilities (e.g., length of time data is to be available for retrieval)</p> <p>Monitoring equipment location requirements:</p> <p>5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)</p> <p>6. Installation requirements:</p> <ul style="list-style-type: none"><li>• substations</li><li>• transmission lines</li></ul> <p>Testing and maintenance requirements:</p> <p>7. Responsibility for maintenance and/or testing</p> <p>Documentation requirements:</p> <p>8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements</p> <p>The Regional requirements shall be provided to other Regions and NERC on request (30 days).</p>	<p>Added a few words to clarify what needs to be required. Additional words were copied from the original measure.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 1 Measure	<p>M1-1. The Regional Reliability Council’s document with its requirements for the installation of disturbance monitoring equipment shall address all elements listed in Standard 057-R1-1</p> <p>M1-2. The Regional Reliability Council shall have evidence it provided its requirements for the installation of disturbance monitoring equipment to other Regional Reliability Councils and NERC on request (30 days).</p>	I.F.M1 Items to be Measured	Regional requirements for the installation of disturbance monitoring equipment.	
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p>On request by NERC (30 business days)</p> <p>NERC</p>	<p>I.F.M1 Timeframe</p> <p>I.F.M1 Compliance Monitoring Responsibility</p>	<p>On request by NERC (30 business days)</p> <p>NERC</p>	
Section 1 Levels of Non-Compliance	<p>Level 1 — The Regional Reliability Council’s disturbance monitoring requirements do not address one of the eight requirements contained in Reliability Standard 057-R1-1.</p> <p>Level 2 — The Regional Reliability Council’s disturbance monitoring requirements do not address two of the eight requirements contained in Reliability Standard 057-R1-1.</p> <p>Level 3 — The Regional Reliability Council’s disturbance monitoring requirements do not address three of the eight requirements contained in Reliability Standard 057-R1-1.</p> <p>Level 4 — The Regional Reliability Council’s disturbance monitoring requirements were not provided or do not address four or more of the eight requirements contained in Reliability Standard 057-R1-1.</p>	I.F.M1 Levels of Non-Compliance	<p>Level 1 - The Region’s disturbance monitoring requirements do not address one of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.</p> <p>Level 2 - The Region’s disturbance monitoring requirements do not address two of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.</p> <p>Level 3 - The Region’s disturbance monitoring requirements do not address three of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	installations to its Regional Reliability Council and NERC on request (30 business days).		5. Operational status 6. Date last tested  Current data on the disturbance monitoring equipment installations shall be provided to the Regions and NERC on request (30 business days).	
Section 2 Measure	<p>M1.The Transmission Owner, and Generator Owner shall have documentation that its disturbance monitoring equipment was installed in accordance with its Regional Reliability Council’s(s’) requirements.</p> <p>M2 The Transmission Owner, and Generator Owner shall provide data on its disturbance monitoring equipment installations to Regional Reliability Councils and NERC on request (30 business days) that shows the equipment’s operational status is in conformance with Standard 057-R2-2.</p>	I.F.M2 Items to be Measured	Disturbance monitoring equipment installations and operational status.	Added M2 to link the levels of non-compliance to the measures. The existing levels of non-compliance assess whether equipment is installed where required and also assesses whether data provided was complete
Section 2 Regional differences	None identified.		None identified.	
Section 2 Compliance Monitoring Process	<p>On request by NERC (30 business days)</p> <p>Regional Reliability Council</p>	I.F.M2 Timeframe  I.F.M2 Compliance Monitoring Responsibility	<p>On request by NERC (30 business days)</p> <p>Regions</p>	
Section 2 Levels of Non-Compliance	Level 1 — Disturbance monitoring equipment is installed at all required locations in accordance with Standard 057-R2-1, however data provided was incomplete and	I.F.M2 Levels of Non-Compliance	Level 1 - Disturbance monitoring equipment is installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, however, the data	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>did not meet one of the six requirements listed in Reliability Standard 057-R2-2.</p> <p>Level 2 — Disturbance monitoring equipment is installed at all required locations in accordance with Standard 057-R2-1, however data provided was incomplete and did not meet two of the six requirements listed in Reliability Standard 057-R2-2.</p> <p>Level 3 — Disturbance monitoring equipment is installed at all required locations in accordance with Standard-057-R2-1, however data provided was incomplete and did not meet three, for or five of the six requirements listed in Reliability Standard-057-R2-2.</p> <p>Level 4 — Disturbance monitoring equipment is not installed at all required locations in accordance with Reliability Standard-057-R2-1, or data for the disturbance monitoring equipment installations was not provided.</p>		<p>provided was incomplete and did not meet one of the six requirements listed above in Measurement M2.</p> <p>Level 2 - Disturbance monitoring equipment is installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, however, the data provided was incomplete and did not meet two of the six requirements listed above in Measurement M2.</p> <p>Level 3 - Disturbance monitoring equipment is installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, however, the data provided was incomplete and did not meet three, four or five of the six requirements listed above in Measurement M2.</p> <p>Level 4 - Disturbance monitoring equipment is not installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, or data for the disturbance monitoring equipment installations was not provided.</p>	
Section 3	Disturbance monitoring data reporting requirements	I.F.M3 Brief Description	Disturbance monitoring data reporting requirements.	
Section 3 Applicability	Regional Reliability Council	I.F.M3 Applicable to	Regions	
Section 3 Requirements		I.F.M3 Standard	<p>S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.</p> <p>M3. Each Region shall establish requirements for entities</p>	
	R3-1 Each Regional Reliability Council shall establish			



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>requirements for entities to provide disturbance-monitoring data to ensure that data is available to determine system performance and the causes of system disturbances. The data reporting requirements shall include:</p> <ol style="list-style-type: none"> <li>1. Definition of “disturbance”</li> <li>2. General requirements for data format</li> <li>3. Data content requirements and guidelines</li> <li>4. Timetable for response to data request</li> <li>5. Requirements for the storage and retention of the disturbance data</li> <li>6. The process for the periodic review and approval of the Regional Reliability Council’s disturbance monitoring data reporting requirements.</li> </ol> <p>R3-2 Each Regional Reliability Council shall provide its Regional disturbance data reporting requirements to other Regional Reliability Councils and NERC on request (five business days).</p>	I.F.M3 Measurement	<p>to provide disturbance monitoring data to ensure that data is available to determine system performance and the causes of system disturbances. Each Region’s disturbance monitoring data reporting requirements shall include:</p> <ol style="list-style-type: none"> <li>1. Definition of “disturbance”</li> <li>2. General requirements for data format</li> <li>3. Data content requirements and guidelines</li> <li>4. Timetable for response to data request</li> <li>5. Requirements for the storage and retention of the disturbance data</li> <li>6. The process for the periodic review and approval of the Region’s disturbance monitoring data reporting requirements</li> </ol> <p>Documentation of Regional data reporting requirements shall be provided to other Regions and NERC on request (five business days).</p>	
Section 3 Measure	<p>M3-1. The Regional Reliability Council’s documented disturbance monitoring data reporting requirements shall include all six elements identified in Reliability Standard 057-R3-1.</p> <p>M3-2. The Regional Reliability Council shall have evidence it provided its disturbance monitoring data reporting requirements to other Regional Reliability Councils and NERC as specified in Reliability Standard 057-R3-2.</p>	I.F.M3 Items to be Measured	Regional disturbance monitoring data reporting requirements.	
Section 3 Regional differences	None identified		None identified	
Section 3 Compliance	On request by NERC (30 business days)	I.F.M3 Timeframe	On request by NERC (30 business days)	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Monitoring Process	NERC	I.F.M3 Compliance Monitoring Responsibility	NERC	
Section 3 Levels of Non-Compliance	<p>Level 1 - The Regional Reliability Council's requirements for providing disturbance monitoring data do not address one of the six areas listed in Standard-057-R3-1.</p> <p>Level 2 - The Regional Reliability Council's requirements for providing disturbance monitoring data do not address two of the six areas listed in Standard-057-R3-1.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - The Regional Reliability Council's requirements for providing disturbance monitoring data were not provided, or the Regional Reliability Council's requirements for providing disturbance-monitoring data do not address three or more of the six areas listed in Standard-057-R3-1.</p>	I.F.M3 Levels of Non-Compliance	<p>Level 1 - The Regional requirements for providing disturbance monitoring data do not address one of the six areas as listed above in Measurement M3.</p> <p>Level 2 - The Regional requirements for providing disturbance monitoring data do not address two of the six areas as listed above in Measurement M3.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - The Regional requirements for providing disturbance monitoring data were not provided, or the Regional requirements for providing disturbance monitoring data do not address three or more of the six areas as listed above in Measurement M3.</p>	
Section 4	Disturbance data	I.F.M4 Brief Description	Disturbance data	
Section 4 Applicability	Transmission Owner, Generator Owner, Transmission Operator, Generator Operator	I.F.M4 Applicable to	Regional members, generation owners, transmission owners.	
Section 4 Requirements	<p>R4-1 The Generator Owner, and Transmission Owner shall each provide its system disturbance data to its Regional Reliability Council(s) in compliance with the respective Regional requirements identified in Standard-057-R3-1.</p> <p>R4-2 The Generator Operator and Transmission Operator shall</p>	I.F.M4 Measurement	<p>S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.</p> <p>M4. Regional members, generation owners, and</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	each provide its current system disturbance data to NERC on request (30 business days).		transmission owners shall provide system disturbance data to the Regions in compliance with the respective Regional requirements identified in Measurement I.F. S2, M3.  The current system disturbance data shall be provided to NERC on request (30 business days).	
Section 4 Measure	M4-1 The Transmission Owner and Generator Owner’s disturbance data shall meet its Regional Reliability Council’s disturbance monitoring data reporting requirements identified in Standard-057-R3-1.  M4-2 The Transmission Operator, and Generator Operator shall have evidence it provided current system disturbance data to NERC on request (30 business days).	I.F.M4 Items to be Measured	System disturbance data.	
Section 4 Regional differences	None identified		None identified	
Section 4 Compliance Monitoring Process	On request by NERC (30 business days)  Regional Reliability Council	I.F.M4 Timeframe  I.F.M4 Compliance Monitoring Responsibility	On request by NERC (30 business days)  Regions	
Section 4 Levels of Non-Compliance	Level 1 - Disturbance data from the disturbance monitoring equipment was provided, however, the data was incomplete and did not meet all of the requirements of the respective Regional Reliability Council’s requirements.  Level 2 - Not applicable.  Level 3 - Not applicable.	I.F.M4 Levels of Non-Compliance	Level 1 - Disturbance data from the disturbance monitoring equipment was provided, however, the data was incomplete and did not meet all of the requirements of the respective Regional requirements.  Level 2 - Not applicable.  Level 3 - Not applicable.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Level 4 - Disturbance data from the disturbance monitoring equipment was not provided.		Level 4 - Disturbance data from the disturbance monitoring equipment was not provided.	
Section 5	Use of disturbance data to develop and maintain models.	I.F.M5 Brief Description	Use of disturbance data to develop and maintain models.	
Section 5 Applicability	Planning Authority, Transmission Planner, Generation Owner	I.F.M5 Applicable to	Regional members	
Section 5 Requirements	R5-1 The Planning Authority, Transmission Planner and Generator Owner shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models.	I.F.M5 Standard  I.F.M5 Measurement	S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.  M5. (old M6) Regional members shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models.	Note that the source document references ‘M5’ which was deleted by the Engineering Committee.
Section 5 Measure	M5-1. The Planning Authority, Transmission Planner and Generator Owner’s steady state and dynamic system models and generator performance models shall reflect use of data from disturbance monitoring equipment.	I.F.M5 Items to be Measured	Use of database in Standard I.F. S1 and S2, M5.	The database referenced in the source document has no logical link to existing Compliance Templates
Section 5 Regional differences	None identified		None identified	
Section 5 Compliance Monitoring Process	On request (30 days)	I.F.M5 Timeframe  Compliance	On request (30 days)  Regions	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Regional Reliability Council	Monitoring Responsibility		
Section 5 Levels of Non-Compliance		I.F.M5 I.F.M5 Levels of Non-Compliance	<p>Level 1 -Documentation of model changes resulting from the Regional database was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Documentation of model changes resulting from the Regional database was not provided on schedule, but was complete when submitted.</p> <p>Level 3 - Documentation of model changes resulting from the Regional database was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Documentation of model changes resulting from the Regional database was not provided.</p>	The source document’s “Items to be Measured” is looking for data to be used in a database that is no longer required, the levels of non-compliance were not translated to Version 0

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	058	Compliance Templates: II.A.M1 II.A.M2 II.A.M3 II.A.M4 II.A.M5 II.A.M6	II. System Modeling Data Requirements  A. System Data	
Title	Requirements for the Submittal of Steady-State and Dynamics Data and Development of System Models	Standard	II. System Modeling Data Requirements  A. System Data	Adopted from brief description in original Planning Standards.
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.			Adopted from brief description in original Planning Standards.
Effective Date	February 8, 2005	BOT Approval Date	II.A.M1-M4 - NERC BOT approved June 12, 2001 (Phase I) II.A.M5-M6 - NERC BOT approved; CTTF approved on April 2, 2004 (Phase III)	
Standard Applicability	Transmission System Owners, Generation Owners, Resource Planners, Distribution Providers, Load Serving Entities, Transmission Planners, Planning Authorities, Transmission Service Providers (Sections 1 and 3)  Regional Reliability Councils (Sections 2, 4, 5, and 6)	Applicability	M1 - Users of the interconnected transmission systems M2 – Regions M3 - Users of the interconnected transmission systems M4 – Regions M5 - Regions M6 - Regions	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 1	Steady-state data for modeling and simulation of the interconnected transmission system	II.A.M1 Brief Description	Steady-state data for modeling and simulation of the interconnected transmission systems.	
Section 1 Applicability	Responsible Entity may be any of the following: Transmission System Owners, Generation Owners, Resource Planners, Distribution Providers, Load Serving Entities, Transmission Planners, Planning Authorities, Transmission Service Providers,	II.A.M1 Applicability	Users of the interconnected transmission systems	Expect that the TSP will have received interchange data from the Interchange Authority
Section 1 Requirements	<div> <div>R1-1</div> <div>The Responsible Entity (as specified within the applicable reporting procedures in Reliability Standard 058-R2-1) shall provide appropriate equipment characteristics, system data, and existing and future interchange transactions in compliance with its respective Interconnection-wide Regional data requirements and reporting procedures for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.</div> </div> <div> <div>R1-2</div> <div>The Responsible Entity (as specified within the applicable reporting procedures in Reliability Standard 058-R2-1) shall provide this data to the Regional Reliability Councils, NERC, and those entities responsible for the reliability of the interconnected transmission systems, as specified within the</div> </div>	<div>II.A.M1 Standard</div> <div>Measure</div>	<div>S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained</div> <div>M1. All the users of the interconnected transmission systems shall provide appropriate equipment characteristics, system data, and existing and future interchange transactions in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A. S1, M2 for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.</div> <div>This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M2). If no schedule exists, then data shall be provided on request (30 business days).</div>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	applicable reporting procedures (Reliability Standard 058-R2-1). If no schedule exists, then the Responsible Entity shall provide on request (30 business days).			
Section 1 Measures	M1-1 The Responsible Entity (as specified within the applicable reporting procedures in Standard 058-R2-1), shall have evidence that it provided equipment characteristics, system data, and interchange transactions for steady-state simulation to the Regional Reliability Councils and NERC as specified in (Standard 058-R1-1 and 058-R1-2)	II.A.M1 Items to be Measured	Equipment characteristics, system data, and interchange transactions for steady-state simulation.	
Section 1 Regional Differences	None.			
Section 1 Compliance Monitoring Process	As specified within the applicable reporting procedures (Reliability Standard 058-R2-M1). If no schedule exists, then on request (30 business days)  Regional Reliability Councils	II.A.M1 Timeframe Compliance  Monitoring Responsibility	As specified within the applicable reporting procedures (standard II.A.S1.M2). If no schedule exists, then on request (30 business days)  Regions	
Section 1 Levels of Non Compliance	Level 1 — Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard 058-R2-1.  Level 2 — Not Applicable  Level 3 — Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard 058-R2-1.	II.A.M1 Levels of Non Compliance	Level 1 — Steady-state data was provided, but was incomplete in one of the seven areas identified in II.A.S1.M2.  Level 2 — Not Applicable  Level 3 — Steady-state data was provided, but were incomplete in two or more of the seven areas identified in II.A.S1.M2.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Level 4 — Steady-state data was not provided.		Level 4 — Steady-state data was not provided.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 2	Maintenance and distribution of steady-state data requirements and reporting procedures	II.A.M2 Brief Description	Maintenance and distribution of steady-state data requirements and reporting procedures.	
Section 2 Applicability	Regional Reliability Councils	II.A.M2 Applicability	Regions	
Section 2 Requirements	<p>R2-1. The Regional Reliability Councils within an Interconnection, in conjunction with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Councils shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:</p> <p>1. Bus (substation and switching station): name, nominal voltage, electrical demand (load) supplied</p>	II.A.M2 Measurement	<p>S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained</p> <p>M2. The Regions, in conjunction with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state and dynamic conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.</p> <p>The following list describes the steady-state data that shall be addressed in the Interconnection-wide requirements:</p> <p>1. Bus (substation and switching station): name, nominal voltage, electrical demand (load) supplied (consistent with</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>(consistent with the aggregated and dispersed substation demand data supplied per Standard 061.), and location.</p> <p>2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.</p> <p>3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard 060) equipment status, and metering locations.</p> <p>4. DC Transmission Line (overhead and underground): Line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.</p> <p>5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard 060.), and equipment status.</p> <p>6. Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller</p>		<p>the aggregated and dispersed substation demand data supplied per Standard II.D.), and location.</p> <p>2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.</p> <p>3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), equipment status, and metering locations.</p> <p>4. DC Transmission Line (overhead and underground): Line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.</p> <p>5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), and equipment status.</p> <p>6. Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.</p> <p>7. Interchange Transactions: Existing and future interchange transactions and/or assumptions.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>device.</p> <p>7. Interchange Transactions: Existing and future interchange transactions and/or assumptions.</p> <p>R2-2 The Regional Reliability Councils within an Interconnection shall document their Interconnection’s data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Councils, NERC, and all users of the interconnected transmission systems on request (five business days).</p>		<p>The data requirements and reporting procedures for each of the NERC interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected transmission systems on request (five business days).</p>	
	<p>M2-1 The Regional Reliability Council shall have documentation of its Interconnection’s steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard 058-R2-2.</p>	<p>II.A.M2 Items to be Measured</p>	<p>Documentation of steady-state data requirements and reporting procedures for each NERC interconnection.</p>	
Section 2 Regional Differences	None identified.		None identified.	
Section 2 Compliance monitoring	<p>Periodic review of data requirements and reporting procedures: at least every five years.</p> <p>NERC</p>	<p>II.A.M2 Timeframe</p> <p>Compliance Monitoring</p>	<p>Data requirements and reporting procedures: on request (5 business days).</p> <p>Periodic review of data requirements and reporting procedures: at least every five years.</p> <p>NERC</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

		Responsibility		
Section 2 Levels of Non Compliance	<p>Level 1 - Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard 058- R2-1.</p> <p>Level 2 - Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard 058-R2-1.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in Reliability Standard 058-R2-1</p>	II.A.M2 Levels of Non Compliance	<p>Level 1 - Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in above Measurement M2.</p> <p>Level 2 - Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in above Measurement M2.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in above Measurement M2.</p>	

Section 3	Dynamics data for modeling and simulation of the interconnected transmission system	II.A.M3 Brief Description	Dynamics data for modeling and simulation of the interconnected transmission systems.	
Section 3 Applicability	Responsible Entity may be any of the following: Transmission System Owners, Generation Owners, Resource Planners, Distribution Providers, Load Serving Entities, Transmission Planners, Planning Authorities, Transmission Service Providers	II.A.M3 Applicability	Users of the interconnected transmission systems	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R3-1 The Responsible Entity (as specified in the reporting procedures of Reliability Standard 058-R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Reliability Standard 058-R4, for the modeling and simulation of the dynamic behavior of the NERC Interconnections: Eastern, Western, and ERCOT.</p> <p>R3-2 This Responsible Entity shall provide data to its Regional Reliability Council(s), NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Reliability Standard 058-R4). If no schedule exists, then the Responsible Entity shall provide data on request (30 business days).</p>	<p>II.A.M3 Standard</p> <p>II.A.M3 Measurement</p>	<p>S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.</p> <p>M3. All users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A. S1, M4 for the modeling and simulation of the dynamic behavior of the NERC Interconnections:</p> <p>Eastern, Western, and ERCOT.</p> <p>This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M4). If no schedule exists, then data shall be provided on request (30 business days).</p>	
Section 3 Measures	M3-1 The Responsible Entity shall have evidence that it provided equipment characteristics and system data in accordance with Reliability Standard 058-R3-1 and Reliability Standard 058-R3-2.	II.A.M3 Items to be Measured	Equipment characteristics and system data for dynamics simulation.	
Section 3 Regional Differences	None identified		None identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Compliance Monitoring Process	As specified within the applicable reporting procedures (Reliability Standard 058-R4). If no schedule exists, then on request (30 business days)  Regional Reliability Council	II.A.M3 Timeframe  II.A.M3 Compliance Monitoring Responsibility	As specified within the applicable reporting procedures (standard II.A.S1.M4). If no schedule exists, then on request (30 business days)  Region	
Section 3 Levels of Non Compliance	Level 1 — Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard 058-R4  Level 2 — Not Applicable  Level 3 — Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard 058-R4  Level 4 — Dynamics data was not provided.	II.A.M3 Levels of Non Compliance	M3:   Level 1 — Dynamics data was provided, but were incomplete in one of the four areas identified in II.A.S1.M4.  Level 2 — Not Applicable  Level 3 — Dynamics data was provided, but was incomplete in two or more of the areas identified in II.A.S1.M4.  Level 4 — Dynamic data was not provided	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 4	Maintenance and distribution of dynamics data requirements and reporting procedures	II.A.M4 Brief Description	Maintenance and distribution of dynamics data requirements and reporting procedures.	
Section 4 Applicability	Regional Reliability Councils	II.A.M4 Applicability	Regions	
Section 4 Requirements	<p>R4-1. The Regional Reliability Council, in coordination with the entities responsible for the reliability of the interconnected transmission systems, 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 Councils 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 address the following:</p> <p>1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation</p>	<p>II.A.M4 Standard</p> <p>II.A.M4 Measurement</p>	<p>S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.</p> <p>M4. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, 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 Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.</p> <p>The following list describes the dynamics data that shall be addressed in the Interconnection-wide requirements:</p> <p>1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant,</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>parameters, and direct and quadrature axes reactance's and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.</p> <p>However, 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.</p> <p>The Interconnection-wide requirements shall specify unit size thresholds for permitting: 1.) the use of non-detailed vs. detailed models, 2.) the netting of small generating units with bus load, and 3.) the combining of multiple generating units at one plant.</p> <p>2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controls, high voltage direct current systems, flexible AC transmission systems, and static compensators.</p> <p>3. Dynamics data representing electrical demand (load) characteristics as a function of frequency and voltage.</p> <p>4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per</p>		<p>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.</p> <p>However, 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.</p> <p>The Interconnection-wide requirements shall specify unit size thresholds for permitting: 1.) the use of non-detailed vs. detailed models, 2.) the netting of small generating units with bus load, and 3.) the combining of multiple generating units at one plant.</p> <p>2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static var controls (SVC), high voltage direct current systems (HVDC), flexible AC transmission systems (FACTS), and static compensators (STATCOM).</p> <p>3. Dynamics data representing electrical demand (load) characteristics as a function of frequency and voltage.</p> <p>4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per IIA.S1.M1.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Reliability Standard 058-R1.</p> <p>R4-2 The Regional Reliability Council 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 on request (within five business days) to Regional Reliability Councils, NERC, and all users of the interconnected systems on request (five business days).</p>		<p>The data requirements and reporting procedures for each of the NERC Interconnections (eastern, Western and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC and all users of the interconnected systems on request (five business days).</p>	
Section 4 Measures	<p>M4-1 The Regional Reliability Councils within each Interconnection shall have documentation of their Interconnection’s dynamics data requirements and reporting procedures.</p>	II.A.M4 Items to be Measured	Documentation of dynamics data requirements and reporting procedures for each NERC interconnection.	
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring Process	<p>Data requirements and reporting procedures: on request (5 business days).</p> <p>Periodic review of data requirements and reporting procedures: at least every five years.</p> <p>NERC</p>	<p>II.A.M4 Timeframe</p> <p>II.A.M4 Compliance Monitoring Responsibility</p>	<p>Data requirements and reporting procedures: on request (5 business days).</p> <p>Periodic review of data requirements and reporting procedures: at least every five years.</p> <p>NERC</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 4 Levels of Non Compliance	<p>Level 1 - Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the four areas defined in Reliability Standard 058-R4-1.</p> <p>Level 2 - Not applicable</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in two or more of the four areas defined in Reliability Standard 058-R4-1.</p>	II.A.M4 Levels of Non Compliance	<p>Level 1 - Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the four areas defined in above Measurement M4.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in two or more of the four areas defined in above Measurement M4.</p>	
Section 5	Development of steady-state system models	II.A.M5 Brief Description	Development of steady-state system models.	
Section 5 Applicability	Regional Reliability Councils in Eastern Interconnection, Interconnection	II.A.M5 Applicability	Regions	
Section 5 Requirements	R5-1 Each of the NERC Interconnections shall develop and maintain a library of solved (converged) steady-state system models. Each Interconnection shall develop models for the near- and longer-term planning horizons	<p>II.A.M5 Standard</p> <p>II.A.M5 Measurement</p>	<p>S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.</p> <p>M5. Each of the NERC Interconnections shall develop and maintain a library of solved (converged) steady-state system models. Models shall be developed for the near- and longer-term planning horizons that are</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels. Within the Eastern Interconnection, the Regional Reliability Councils shall coordinate and jointly develop the steady-state system models for that Interconnection.</p> <p>Each Interconnection shall develop steady-state system models annually for selected study years, as determined by that Interconnection. The Interconnection shall provide the most recent solved (converged) steady-state models to Regional Reliability Councils and NERC on request (30 days).</p>		<p>representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels. Within the Eastern Interconnection, the Regions shall coordinate and jointly develop the steady-state system models for that Interconnection.</p> <p>Steady-state system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent solved (converged) steady-state models shall be provided to the Regions and NERC on request (30 days).</p>	
Section 5 Measures	M5-1 Each Interconnection shall have Interconnection steady-state system models.	II.A.M5 Items to be Measured	Development of Interconnection steady-state system models.	
Section 5 Regional Differences	None identified.		None identified.	
Section 5 Compliance Monitoring Process	Development of steady-state system models: annually. Most recent steady-state system models: 30 days.  NERC	II.A.M5 Timeframe  II.A.M5 Compliance Monitoring Responsibility	Development of steady-state system models: annually. Most recent steady-state system models: 30 days.  NERC	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 5 Levels of Non Compliance	<p>An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.</p> <p>Level 1 - One of a Regional Reliability Council’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.</p> <p>Level 2 - Two of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 3 - Three of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 4 - Four or more of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p>	II.A.M5 Levels of Non Compliance	<p>An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.</p> <p>Level 1 - One of a Region’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.</p> <p>Level 2 - Two of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 3 - Three of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 4 - Four or more of a Region’s cases were either not submitted by the data submission</p>	The levels of non-compliance are assessed against the Regions, but there are no Regional requirements.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).	
Section 6	Development of dynamics system models	II.A.M6 Brief Description	Development of dynamics system models.	
Section 6 Applicability	Regional Reliability Councils, Interconnection	II.A.M6 Applicability	Regions	
Section 6 Requirements	R6-1 Each of the Interconnections shall develop and maintain a library of initialized (with no faults or system disturbances) dynamics system models. Models shall be developed for at least two timeframes (present or near-term model and a future or longer-term model). Additional seasonal and demand level models shall be developed, as necessary, to analyze the dynamic response of each of the NERC Interconnections: Eastern, Western, and ERCOT. These dynamics system models shall be linked to the steady-state system models, as appropriate, of Standard II.A.M5. Within the Eastern Interconnection, the Regions shall coordinate	II.A.M6 Standard  II.A.M6 Measure	S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.  M6. Each of the Interconnections shall develop and maintain a library of initialized (with no faults or system disturbances) dynamics system models. Models shall be developed for at least two timeframes (present or near-term model and a future or longer-term model). Additional seasonal and demand level models shall be developed, as necessary, to analyze the dynamic response of each of the NERC Interconnections: Eastern, Western, and ERCOT. These dynamics system models shall be linked to the steady-state system models, as appropriate, of Standard II.A.M5. Within the	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>and jointly develop the dynamics system models for that Interconnection.</p> <p>The Regional Reliability Councils within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models shall be provided to the Regions and NERC on request (30 days).</p>		<p>Eastern Interconnection, the Regions shall coordinate and jointly develop the dynamics system models for that Interconnection.</p> <p>Dynamics system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent initialized (approximately 25 seconds, no-fault) models shall be provided to the Regions and NERC on request (30 days).</p>	
Section 6 Measures	M6-1 The Regional Reliability Council shall have evidence that it contributed to the development of its Interconnection dynamics system models in accordance with Reliability Standard 058-R6-1.	II.A.M6 Items to be Measured	Items to be Measured – Development of Interconnection dynamics system models.	
Section 6 Regional Differences	None identified		None identified	
Section 6 Compliance Monitoring Process	<p>Development of dynamics system models: annually.</p> <p>Most recent dynamics system models: 30 days.</p> <p>NERC</p>	<p>II.A.M6 Timeframe</p> <p>II.A.M6 Compliance Monitoring Responsibility</p>	<p>Development of dynamics system models: annually.</p> <p>Most recent dynamics system models: 30 days.</p> <p>NERC</p>	
Section 6 Levels of Non	An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.	II.A.M6 Levels of Non-	An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Compliance	<p>Level 1 - One of a Regional Reliability Council’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.</p> <p>Level 2 - Two of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 3 - Three of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 4 - Four or more of a Regional Reliability Council’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p>	compliance	<p>Level 1 - One of a Region’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.</p> <p>Level 2 - Two of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 3 - Three of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p> <p>Level 4 - Four or more of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	059	Compliance Templates II.B.M1 II.B.M2 II.B.M3 II.B.M4 II.B.M5 II.B.M6	II. System Modeling Data Requirements B. Generation Equipment	
Title	System Modeling Data Requirements - Generation Equipment	Section	II. System Modeling Data Requirements B. Generation Equipment	
Purpose	Validation of generator modeling data, through field verification and testing, to provide accurate, validated generator models and data required in planning and operating studies used to ensure electric system reliability.			
Effective Date	February 8, 2005 all Sections	Approval dates	II.B.M1-6 Approved by Engineering Committee: July, 14, 1998 - Phase IV	
Standard Applicability	Section 1 Regional Reliability Council Section 2 Generator Owner Section 3 Generator Owner Section 4 Generator Owner Section 5 Generator Owner Section 6 Generator Owner	Applicable to	II.B. M1 Regions II.B. M2 Generation equipment owners II.B. M3 Generation equipment owners II.B. M4 Generation equipment owners II.B.M5 Generation equipment owners II.B. M6 Generation equipment owners	
Section 1	Regional procedures for generation equipment testing.	II.B.M1 Brief	Regional procedures for generation equipment testing.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

		Description		
Section 1 Applicability	Regional Reliability Council	II.B.M1 Applicable to	Regions	
Section 1 Requirements	<p>R1-1. Each Regional Reliability Council shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures. These procedures shall contain the schedule for the testing of the generation equipment and the schedule for the submittal of the verification or test data to the Regional Reliability Councils shall be included in the Regional procedures.</p>	<p>II.B.M1 Standard</p> <p>Measurements</p> <p>Full (100%) Compliance Requirement</p>	<p>S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.</p> <p>M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures.</p> <p>Full (100%) Compliance Requirement Each Region shall establish, maintain, and document procedures for generation equipment data verification and testing for all non-exempt generating units in its Region. The equipment to be tested and the data to be reported shall</p>	<p>Measurement M1 and the Full (100%) Compliance Requirement were merged to produce Requirement R1-1.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	R1-2 The Regional Reliability Council’s documentation of verification and testing procedures shall be available to all reporting parties on request (five business days).		include, as a minimum, those items specified under Measurements M1, M2, M3, M4, M5, and M6 of this Standard II.B. S1. The schedule for the testing of the generation equipment, as defined in Measurements M2, M3, M4, M5, and M6, and the schedule for the submittal of the verification or test data to the Regions shall be included in the Regional procedures. Each Region shall also develop the criteria under which generation equipment may be exempt from a portion or all of the required testing procedures. A list of the exempt units shall be maintained by each Region. Documentation of verification and testing procedures shall be available to all reporting parties on request (five business days).	
Section 1 Measures	<p>M1-1. The Regional Reliability Council’s procedures for validating generation equipment data shall contain all items identified in Reliability Standard 059-R1-1.</p> <p>M1-2 The Regional Reliability Council shall have evidence it provided documentation of its procedures for validating generation equipment data on request (five business days).</p>	<p>II.B.M1</p> <p>Items to be measured</p>	<p>Procedures for validating generation equipment data.</p>	
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring	On request (five business days).	<p>II.B.M1 Timeframe</p> <p>Compliance Monitoring</p>	On request (five business days).	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Process	NERC	Responsibility	NERC	
Section 1  Levels of Non Compliance	<p>Level 1 - Documentation of Regional Reliability Council procedures for generation equipment testing was provided when requested, but was incomplete in one or more areas.</p> <p>Level 2 - Documentation of Regional procedures for generation equipment testing was not provided when requested, but was complete when submitted.</p> <p>Level 3 - Documentation of Regional Reliability Council procedures for generation equipment testing was not provided when requested, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Documentation of Regional Reliability Council procedures for generation equipment testing was not provided.</p>	III.C.M1 Levels of Non-Compliance	<p>Level 1 - Documentation of Regional procedures for generation equipment testing was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Documentation of Regional procedures for generation equipment testing was not provided on schedule, but was complete when submitted.</p> <p>Level 3 - Documentation of Regional procedures for generation equipment testing was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Documentation of Regional procedures for generation equipment testing was not provided.</p>	
Section 2	Verification of gross and net real power dependable capability of generators.	II.B.M2  Brief Description	Verification of gross and net real power dependable capability of generators.	
Section 2  Applicability	Generator Owner	II.B.M2  Applicable to	Generation equipment owners	
Section 2  Requirements		II.B.M2  Standard	S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The	Measurement M2 and the Full (100%) Compliance Requirement were merged to

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R2-1 The Generator Owner shall annually test to verify the gross and net dependable capability of its units. The Generator Owner shall provide the Regional Reliability Council(s) with the following information on request:</p> <ul style="list-style-type: none"><li>a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.</li><li>b. Active or real power requirements of auxiliary loads.</li><li>c. Date and conditions during tests (ambient and design temperatures, generator loading, voltages, hydrogen pressure, high-side voltage, and auxiliary loads).</li></ul> <p>Test conditions and test results shall be documented and all data requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Section 1 of Standard 059. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.</p>	<p>Measurements</p> <p>Full (100%) Compliance Requirement</p>	<p>data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.</p> <p>M2. Generation equipment owners shall annually test to verify the gross and net dependable capability of their units. They shall provide the Regions with the following information on request:</p> <ul style="list-style-type: none"><li>a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.</li><li>b. Active or real power requirements of auxiliary loads.</li><li>c. Date and conditions during tests (ambient and design temperatures, generator loading, voltages, hydrogen pressure, high-side voltage, and auxiliary loads).</li></ul> <p>Generation equipment owners shall test annually all of their non-exempt generation equipment for summer and winter gross and net real power (MW) dependable capability according to the Regional procedures under Measurement M1 of this Standard II.B. S1. Operating data may be acceptable as test data providing it was obtained under test-like</p>	<p>produce Requirement R2-1.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			<p>conditions.</p> <p>Test conditions and test results shall be documented and all data requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.</p>	
<p>Section 2</p> <p>Measures</p>	<p>M2-1. The Generator Owner shall have documentation of its verification of gross and net real power dependable capability of generators as specified in Reliability Standard 059-R2-1.</p> <p>M2-2 The Generator Owner shall have evidence it provided the Regional Reliability Council(s) with verification of generator gross and net real power dependable capability as specified in Reliability Standard 059-R2-1.</p>	<p>II.B.M2</p> <p>Items to be measured</p>	<p>Verification of gross and net dependable capability of generators.</p>	
<p>Section 2</p> <p>Regional Differences</p>	<p>None identified</p>		<p>None identified</p>	
<p>Section 2</p> <p>Compliance Monitoring Process</p>	<p>Annually.</p> <p>Regional Reliability Council</p>	<p>II.B.M2</p> <p>Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Annually.</p> <p>Regions</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Levels of Non Compliance	<p>Level 1 - Verification of generator gross and net real power dependable capability was provided on schedule, but was incomplete in one or more areas</p> <p>Level 2 - Verification of generator gross and net real power dependable capability was not provided on schedule, but was complete when submitted.</p> <p>Level 3 - Verification of generator gross and net real power dependable capability was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Verification of generator gross and net real power dependable capability was not provided.</p>	II.B.M2 Levels of Non-Compliance	<p>Level 1 - Verification of generator gross and net real power dependable capability was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Verification of generator gross and net real power dependable capability was not provided on schedule, but was complete when submitted.</p> <p>Level 3 - Verification of generator gross and net real power dependable capability was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Verification of generator gross and net real power dependable capability was not provided.</p>	
Section 3	Verification of gross and net reactive power capability of generators.	II.B.M3 Brief Description	Verification of gross and net reactive power capability of generators.	
Section 3 Applicability	Generator Owner	II.B.M3 Applicable to	Generation equipment owners	
Section 3 Requirements		II.B.M3 Standard	S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator	Measurement M3 and the Full (100%) Compliance Requirement were merged to produce Requirement R3-1.





Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

			generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.	
Section 3 Measures	<p>M3-1. The Generator Owner’s documentation of its verification of gross and net reactive power capability of generators shall contain all items specified in Standard 059-R3-1.</p> <p>M3-2 The Generator Owner shall have evidence it provided the Regional Reliability Council(s) with documentation of its verification of gross and net reactive power capability of generators as specified in Reliability Standard 059-R3-1.</p>	<p>II.B.M3</p> <p>Items to be measured</p>	Verification of gross and net reactive power capability of generators.	
Section 3 Regional Differences	None identified		None identified	
Section 3 Compliance Monitoring Process	<p>At least every five years.</p> <p>Regional Reliability Council</p>	<p>II.B.M3 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>At least every five years.</p> <p>Regions</p>	
Section 3 Levels of Non Compliance	<p>Level 1 -Verification of generator gross and net reactive power capability was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Verification of generator gross and net reactive power capability was not provided on schedule, but was</p>	<p>II.B.M3 Levels of Non-</p>	<p>Level 1 - Verification of generator gross and net reactive power capability was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Verification of generator gross and net reactive power capability was not provided on schedule, but was completed when submitted.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>completed when submitted.</p> <p>Level 3 - Verification of generator gross and net reactive power capability was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Verification of generator gross and net reactive power capability was not provided.</p>	Compliance	<p>Level 3 - Verification of generator gross and net reactive power capability was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Verification of generator gross and net reactive power capability was not provided.</p>	
Section 4	Test results of generator voltage regulator controls and limit functions.	II.B.M4 Brief Description	Test results of generator voltage regulator controls and limit functions.	
Section 4 Applicability	Generator Owner	II.B.M4 Applicable to	Generation equipment owners	
Section 4 Requirements	R4-1. The Generator Owner shall test its voltage regulator	II.B.M4 Standards  Measurement	<p>S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.</p> <p>M4. Generation equipment owners shall test voltage</p>	Measurement M4 and the Full (100%) Compliance Requirement were merged to produce Requirement R4-1.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>controls and limit functions at least every five years. Upon request, the Generator Owner shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator’s short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting.</p> <p>All test data and status information requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Section 1 of Standard 059. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.</p>	Full (100%) Compliance Requirement	<p>regulator controls and limit functions at least every five years. Upon request, they shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator’s short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting.</p> <p>Generation equipment owners shall test at least every five years all of their non-exempt voltage regulator controls and limit functions in accordance with Measurement M4 above and the Regional procedures required under Measurement M1 of this Standard II.B. S1.</p> <p>All test data and status information requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.</p>	
Section 4 Measures	<p>M4-1. The Generator Owner shall have documentation of test results of generator voltage regulator controls and limit functions as specified in Standard 059-R4-1.</p> <p>M4-2 The Generator Owner shall have evidence it provided the Regional Reliability Council(s) with test data and status information as specified in Reliability Standard 059-R4-</p>	II.B.M4 Items to be measured	Test results of generator voltage regulator controls and limit functions.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	1.			
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring Process	At least every five years.  Regional Reliability Council	II.B.M4 Timeframe  Compliance Monitoring Responsibility	At least every five years.  Regions	
Section 4 Levels of Non Compliance	Level 1 - Test results of generator voltage regulator controls and limit functions were provided on schedule, but were incomplete in one or more areas.  Level 2 - Test results of generator voltage regulator controls and limit functions were not provided on schedule, but were complete when submitted.  Level 3 - Test results of generator voltage regulator controls and limit functions were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Test results of generator voltage regulator controls and limit functions were not provided.	II.B.M4 Levels of Non-Compliance	Level 1- Test results of generator voltage regulator controls and limit functions were provided on schedule, but were incomplete in one or more areas.  Level 2 - Test results of generator voltage regulator controls and limit functions were not provided on schedule, but were complete when submitted.  Level 3 - Test results of generator voltage regulator controls and limit functions were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Test results of generator voltage regulator controls and limit functions were not provided.	
Section 5	Test results of speed/load governor controls.	II.B.M5  Brief	Test results of speed/load governor controls.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

		Description		
Section 5 Applicability	Generator Owner	II.B.M5  Applicable to	Generation equipment owners	
Section 5 Requirements	<p>R5-1. The Generator Owner shall test its speed/load governor controls at least every five years. Upon request, the Generator Owner shall provide the Regional Reliability Council(s) with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system.</p> <p>All test data and status information requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Section 1 of Standard 059. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.</p>	<p>II.B.M5 Standard</p> <p>Measurement</p> <p>Full (100%) Compliance Requirement</p>	<p>S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.</p> <p>M5. Generation equipment owners shall test speed/load governor controls at least every five years. Upon request, they shall provide the Regions with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system.</p> <p>Generation equipment owners shall test at least every five years all of their non-exempt speed/load governor controls according to the Regional procedures required under Measurement M1 of this Standard II.B. S1. They shall also provide on request (within 30 days) information on the characteristics (droop and deadband) of the speed/load governing system.</p> <p>All test data and status information requested by the Region</p>	Measurement M5 and the Full (100%) Compliance Requirement were merged to produce Requirement R5-1.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.	
Section 5 Measures	<p>M5-1. The Generator Owner shall have documentation of its test results of speed/load governor controls as specified in Standard 059-R5-1.</p> <p>M5-2 The Generator Owner shall have evidence it provided the Regional Reliability Council(s) with documentation of its test data and status of speed/load governor controls as specified in Reliability Standard 059-R5-1.</p>	<p>II.B.M5</p> <p>Items to be measured</p>	Test results of speed/load governor controls.	
Section 5 Regional Differences	None identified		None identified	
Section 5 Compliance Monitoring Process	<p>At least every five years.</p> <p>Regional Reliability Council</p>	<p>II.B.M5</p> <p>Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>At least every five years.</p> <p>Regions</p>	
Section 5 Levels of Non Compliance	<p>Level 1 - Test results of speed/load governor controls were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Test results of speed/load governor controls were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Test results of speed/load governor controls were not provided on schedule, and were incomplete in one or</p>	<p>II.B.M5</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - Test results of speed/load governor controls were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Test results of speed/load governor controls were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Test results of speed/load governor controls were not provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Test results of speed/load governor controls were</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>more areas when submitted.</p> <p>Level 4 - Test results of speed/load governor controls were not provided.</p>		not provided.	
Section 6	Verification of excitation system dynamic modeling data.	II.B.M6 Brief Description	Verification of excitation system dynamic modeling data.	
Section 6 Applicability	Generator Owner	II.B.M6 Applicable to	Generation equipment owners	
Section 6 Requirements	<p>R6-1. The Generator Owner shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. The Generator Owner shall provide design data for new or refurbished excitation systems at least one year prior to the in-service date with updated data provided once the unit is in service. The Generator</p>	<p>II.B.M6 Standard</p> <p>Measurements</p>	<p>S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.</p> <p>M6. Generation equipment owners shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. Design data for new or refurbished excitation systems shall be provided at least one year prior to the in-service date with updated data provided once</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Owner shall provide open circuit test response chart recordings showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.)		the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.)	
Section 6 Measures	<p>M6-1. The Generator Owner shall have documentation of its verification of excitation system dynamic modeling data as specified in Reliability Standard 059-R6-1.</p> <p>M6-2 The Generator Owner shall have evidence it provided the Regional Reliability Council(s) with verification of its excitation system dynamic modeling data as specified in Reliability Standard 059-R6-1.</p>	II.B.M6  Items to be measured	Verification of excitation system dynamic modeling data.	
Section 6 Regional Differences	None identified		None identified	
Section 6 Compliance Monitoring Process	<p>At least every five years.</p> <p>Regional Reliability Council</p>	II.B.M6 Timeframe  Compliance Monitoring Responsibility	<p>At least every five years.</p> <p>Regions</p>	
Section 6 Levels of Non Compliance	<p>Level 1 - Verification of excitation system dynamic modeling data was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Verification of excitation system dynamic modeling data was not provided on schedule, but was complete when submitted.</p> <p>Level 3 -Verification of excitation system dynamic modeling data</p>	II.B.M6 Levels of Non-Compliance	<p>Level 1 - Verification of excitation system dynamic modeling data was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Verification of excitation system dynamic modeling data was not provided on schedule, but was complete when submitted.</p> <p>Level 3 - Verification of excitation system dynamic modeling data was not provided on schedule, and</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

	was not provided on schedule, and was incomplete in one or more areas when submitted.  Level 4 - Verification of excitation system dynamic modeling data was not provided.		was incomplete in one or more areas when submitted. Level 4 - Verification of excitation system dynamic modeling data was not provided.	
--	--	--	--	--

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	060	Compliance Templates II.C.M1 II.C.M2	II. System Modeling Data Requirements C. Facility Ratings	
Title	Facility Ratings	Section	II. System Modeling Data Requirements C. Facility Ratings	
Purpose	To ensure that electrical facilities used in the transmission and storage of electricity are rated in compliance with applicable Regional Reliability Council requirements.		S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional requirements.	Purpose was paraphrased from the Standard S1
Effective Date	February 8, 2005	Approval Dates	II.C.M1 CTTF Revised Compliance Template, NERC BOT Approved – April 2, 2004 II.C.M2 NERC BOT approved in Phase I – June 12, 2001	
Standard Applicability	Transmission Owner and Generator Owner	Applicable to	M1 – Facility owners M2 - Facility owners	
Section 1	Methodology(ies) for Determining Electrical Facility Ratings	II.C.M1 Brief Description	Methodology(ies) for determining electrical facility ratings.	
Section 1 Applicability	Transmission Owner and Generator Owner	II.C.M1 Applicable to	Facility owners	
Section 1 Requirements	R1-1 The Transmission Owner and Generator Owner shall document the methodology(s) used to determine its electrical facility and equipment rating. Further, the methodology(s) shall comply with applicable Regional Reliability Council requirements. The documentation shall address and include: 1. The methodology(s) used to determine facility and equipment rating of the items listed for both normal and emergency conditions: a. Transmission circuits	II.C.M1 Standard  II.C.M1 Measure	S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional requirements.  M1. Facility owners shall document the methodology(s) used to determine their electrical facility and equipment rating. Further, the methodology(s) shall be compliant with applicable Regional requirements. The documentation shall address and include:  1. The methodology(s) used to determine facility and equipment rating of the items listed for both normal and emergency conditions:	Changed Regional to Regional Reliability Council to match the Functional Model  Changed Facility owners to Transmission Owners and Generation Owners to match the Functional Model

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<ul style="list-style-type: none"> <li>b. Transformers</li> <li>c. Series and shunt reactive elements</li> <li>d. Terminal equipment (e.g., switches, breakers, current transformers, etc.)</li> <li>e. VAR compensators (SVC)</li> <li>f. High voltage direct current (HVDC) converters</li> <li>g. Any other device listed as a limiting element</li> </ul> <p>2. The rating of a facility shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment.</p> <p>3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.</p> <p>4. Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of ratings.</p> <p>5. The documentation shall identify the assumptions used to determine each of the facility and equipment ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.</p> <p>R1-2 The Transmission Owner and Generator Owner shall provide documentation of the methodology(ies) used to determine its transmission facility ratings to the Regional Reliability Council(s) and NERC on request (five business days).</p>		<ul style="list-style-type: none"> <li>a. Transmission circuits</li> <li>b. Transformers</li> <li>c. Series and shunt reactive elements</li> <li>d. Terminal equipment (e.g., switches, breakers, current transformers, etc.)</li> <li>e. VAR compensators (SVC)</li> <li>f. High voltage direct current (HVDC) converters</li> <li>g. Any other device listed as a limiting element</li> </ul> <p>2. The rating of a facility shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment.</p> <p>3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.</p> <p>4. Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of ratings.</p> <p>5. The documentation shall identify the assumptions used to determine each of the facility and equipment ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.</p> <p>The documentation of the methodology(ies) used to determine transmission facility ratings shall be provided to the Regions and NERC on request (five business days).</p>	
Section 1 Measure	M1-1 The Transmission Owner or Generator Owner shall provide documentation that the methodology(ies) used for determining facility ratings meets the requirements of Standard	II.C.M1 Items to be Measured	Methodology(ies) used for determining facility ratings.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	060-R1-1 as specified in Standard 060-R1-2.			
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	On request (five business days).  Regional Reliability Council.	II.C.M1 Timeframe  Compliance Monitoring Responsibility	On request (five business days).  Regions.	
Section 1 Levels of Non-Compliance	Level 1 - Facility and equipment rating methodology(s) do not address one of the five elements (1-5) listed in Reliability Standard 060-R1-1. Level 2 - N/A Level 3 - Facility and equipment rating methodology(s) do not address two of the five elements (1-5) listed in Reliability Standard 060-R1-1. Level 4 - Facility and equipment rating methodology(s) do not address three or more of the five elements (1-5) listed in Reliability Standard 060-R1-1, or no facility and equipment rating methodology was provided.	II.C.M1 Levels of Non-Compliance	Level 1 - Facility and equipment rating methodology(s) do not address one of the requirements listed in the above Measurement M1. Level 2 - N/A Level 3 - Facility and equipment rating methodology(s) do not address two of the requirements listed in the above Measurement M1. Level 4 - Facility and equipment rating methodology(s) do not address three or more of the requirements listed in the above Measurement M1, or no facility and equipment rating methodology was provided.	Changed “requirements” to “elements” to prevent confusion with Requirements
Section 2	Electrical facility ratings for system modeling.	II.C.M2 Brief Description	Electrical facility ratings for system modeling.	
Section 2 Applicability	Transmission Owner, Generator Owner	II.C.M2 Applicable to	Facility Owners	
Section 2 Requirements	R2-1 The Transmission owner, and Generator Owner shall have on file or be able to readily provide, a document or database identifying the normal and emergency ratings of all of their transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the bulk interconnected transmission systems. Seasonal variations in ratings shall be included as appropriate.	II.C.M2 Standard  II.C.M2 Measure	M2. Facility owners shall have on file or be able to readily provide, a document or database identifying the normal and emergency ratings of all of their transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the bulk interconnected transmission systems. Seasonal variations in ratings shall be included as appropriate.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>The ratings shall be consistent with the methodologies for determining facility ratings and shall be updated as facility changes occur.</p> <p>R2-2 The Transmission Owner and Generator Owner shall provide the normal and emergency ratings of all its transmission facilities to the Regional Reliability Council(s) and NERC on request (30 business days)</p>		<p>The ratings shall be consistent with the methodologies for determining facility ratings and shall be updated as facility changes occur. The ratings shall be provided to the Regions and NERC on request (30 business days)</p>	
Section 2 Measures	M2-1 The Transmission Owner and Generator Owner shall provide documentation of its facility ratings as specified in Reliability Standard 060-R2-1 and Standard 060-R2-2.	II.C.M2 Items to be Measured	Electrical facility ratings (normal and emergency, as appropriate).	
Section 2 Regional Differences	None identified		None identified	
Section 2 Compliance Monitoring Process	<p>On request (30 days).</p> <p>Regional Reliability Council.</p>	II.C.M2 Timeframe  Compliance Monitoring Responsibility	<p>On request (30 days).</p> <p>Regions.</p>	
Section 2 Levels of Non-Compliance	<p>Level 1 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in one facility type.</p> <p>Level 2 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in two facility types.</p> <p>Level 3 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in three or more facility types.</p> <p>Level 4 - Facility ratings were not provided.</p>	II.C.M2 Levels of Non-Compliance	<p>Level 1 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in one facility type.</p> <p>Level 2 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in two facility types.</p> <p>Level 3 - Facility ratings were incomplete or the methodology(ies) inconsistently applied in three or more facility types.</p> <p>Level 4 - Facility ratings were not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	061	Compliance Templates II.D.M1 II.D.M2 II.D.M3 II.D.M4 II.D.M6 II.D.M10 II.D.M11 II.D.M12	II. System Modeling Data Requirements  D. Actual and Forecast Demands	
Title	Actual and Forecast Demands	Sections	II. System Modeling Data Requirements  D. Actual and Forecast Demands	
Purpose	To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for the continued reliability. In addition to assist in proper real time operating, load information related to controllable demand-side management programs is needed.	Introduction for II.D	Actual demand data is needed for forecasting future electrical requirements, reliability assessments of past electric system events, load diversity studies, and validation of databases.  Forecast demand data is needed for system modeling and the analysis of the adequacy and security of the interconnected bulk electric systems, and for identifying the need and timing of system reinforcements to reliably supply customer electrical requirements.  Actual and forecast demand data generally includes hourly, monthly, and annual demands and monthly and annual net energy for load. This data may be required on an aggregated Regional, subregional, power pool, individual system basis, or on a dispersed transmission substation basis for system modeling and reliability analysis.	Paraphrased the Introduction for II.D

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			In addition to demands and net energy for load, that portion of demand that is included in or part of controllable demand-side management programs and which may be interrupted by system operators also may be required in evaluating the adequacy and security of the interconnected bulk electric systems.	
Effective Date	February 8, 2005	Approval Dates	<p>II.D.M1 &amp; II.D.M4 &amp; II.D.M10, introduced in Phase 1, NERC BOT approved June 12, 2001</p> <p>II.D.M2 &amp; II.D.M3, proposed for Phase 4, NERC Engineering Committee approved July 14, 1998</p> <p>II.D.M6 &amp; II.D.M11 &amp; II.D.M12, introduced in Phase 2, NERC BOT approved October 16, 2001</p>	
Standard Applicability	<p>II.D.M1 &amp; II.D.M2, Planning Authority and Regional Reliability Council</p> <p>II.D.M3 &amp; II.D.M4 &amp; II.D.M6 &amp; II.D.M10 &amp; II.D.M11 &amp; II.D.M12, Load Serving Entity, Planning Authority and Resource Planner</p>	Applicability	<p>II.D.M1, Entities responsible for the reliability of the interconnected transmission systems and the Regions.</p> <p>II.D.M2, Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions.</p> <p>II.D.M3, Entities required to report actual and forecast demand data.</p> <p>II.D.M4 &amp; II.D.M6 &amp; II.D.M10 &amp; II.D.M12, Entities required by the Region to report actual and forecast demand data.</p> <p>II.D.M11, Entities responsible for the reliability of the</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			interconnected transmission systems.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 1	Documentation of data reporting requirements for actual and forecast demands, net energy for load, and controllable demand-side management.	Brief Descriptions II.D.M1	Documentation of data reporting requirements for actual and forecast demands, net energy for load, and controllable demand-side management.	
Section 1 Applicability	Planning Authority and Regional Reliability Council.	II.D.M1 Applicable to	Entities responsible for the reliability of the interconnected transmission systems and the Regions.	Incorporated Functional Model terminology
Section 1 Requirements	<p>R1-1. The Planning Authority and Regional Reliability Council 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 demand-side management data to be reported for system modeling and reliability analyses.</p> <p>The aggregated and dispersed data submittal requirements shall</p>	<p>Standards for II.D.M1</p> <p>II.D.M1 Measurements</p>	<p>S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.</p> <p>Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.</p> <p>S2.Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.</p> <p>M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, 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 demand-side management data to be reported for system modeling and</p>	The content of S1 and S2 related to this section is repeated and detailed more completely in the M1 measurement and therefore not used directly in translation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>ensure that consistent data is supplied for Reliability Standards 052, 058, and 061.</p> <p>R1-2. The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).</p>		<p>reliability analyses.</p> <p>The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Standards IB, IIA, and IID.</p> <p>The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).</p>	Reference to current Standards were replaced with Version 0 Standards
Section 1 Measures	M1-1 The Planning Authority and Regional Reliability Council shall provide evidence that it provided data and reporting procedures per Reliability Standard 061 R1-1 and R1-2.	II.D.M1 Items to be Measured	Scope and details of demand, net energy for load, and controllable demand-side management data and reporting procedures.	Incorporated Functional Model terminology.
Section 1 Regional Differences	None identified	None	None identified	
Section 1 Compliance Monitoring Process	<p>Regional Reliability Council and NERC.</p> <p>On request (five business days).</p>	<p>II.D.M1 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Regions and NERC.</p> <p>On request (five business days).</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - The Region and the entities responsible for the reliability of the interconnected transmission systems have identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures but have not specified that consistent data is to be supplied for Reliability Standards 052, 058, and 061.</p> <p>Level 2 - Not applicable.</p>	<p>II.D.M1 Levels of non-compliance</p>	<p>Level 1 - The Region and the entities responsible for the reliability of the interconnected transmission systems have identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures but have not specified that consistent data is to be supplied for Standards I.B, II.A, and II.D.</p> <p>Level 2 - Not applicable.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 - Not applicable.</p> <p>Level 4 - The Region and the entities responsible for the reliability of the interconnected transmission systems have not identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures.</p>		<p>Level 3 - Not applicable.</p> <p>Level 4 - The Region and the entities responsible for the reliability of the interconnected transmission systems have not identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures.</p>	
Section 2	Reporting procedures to ensure against double counting or the omission of customer demand data.	Brief Descriptions II.D.M2	Reporting procedures to ensure against double counting or the omission of customer demand data.	
Section 2 Applicability	Planning Authority and Regional Reliability Council.	II.D.M2 Applicable to	Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions.	
Section 2 Requirements	<p>R2-1. The Planning Authority and Regional Reliability Council reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region.</p> <p>R2-2. The Planning Authority and Regional Reliability Council data reporting procedures shall be available on request (five business days) to the Regions and NERC.</p>	<p>II.D.M2 Standard</p> <p>II.D.M2 Measurement</p> <p>II.D.M2 Full (100%) Compliance Requirement</p>	<p>S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.</p> <p>M2. The reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region.</p> <p>The data reporting procedures shall adequately address prevention of double counting, the omission of data in accordance with Measurement M2 above, and shall be available on request (five business days) to the Regions and</p>	The content of S1 related to this section is repeated and detailed more completely in the Measurement and Full (100%) Compliance Requirement and therefore not used directly in translation

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			NERC.	
Section 2 Measures	M2-1 The Planning Authority and Regional Reliability Council shall provide evidence that it provided data reporting procedures per Reliability Standard 061 R2-1 and R2-2.	II.D.M2 Items to be Measured	Reporting procedures that ensure against double counting or the omission of customer demand data.	Added words to the language to make a measurable standard.
Section 2 Regional Differences	None identified	None	None identified	
Section 2 Compliance Monitoring Process	On request (five business days)  NERC and the Regional Reliability Council	II.D.M2 Timeframe  Compliance Monitoring Responsibility	On request (five business days)  Regions and NERC	
Section 2 Levels of Non Compliance	Level 1 - Reporting procedures that address double counting and the omission of data were provided on schedule, but were incomplete in one or more areas.  Level 2 - Reporting procedures that address double counting and the omission of data were not provided on schedule, but were complete when submitted.  Level 3 - Reporting procedures that address double counting and the omission of data were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Reporting procedures that address double counting and the omission of data were not provided.	II.D.M2 Levels of Non-Compliance	Level 1 - Reporting procedures that address double counting and the omission of data were provided on schedule, but were incomplete in one or more areas.  Level 2 - Reporting procedures that address double counting and the omission of data were not provided on schedule, but were complete when submitted.  Level 3 - Reporting procedures that address double counting and the omission of data were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Reporting procedures that address double counting and the omission of data were not provided.	No Changes
Section 3	Consistency of actual and forecast demands and controllable demand-side management data reported for reliability and to	Brief Descriptions	Consistency of actual and forecast demands and controllable demand-side management data reported for	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	government agencies.	II.D.M3	reliability and to government agencies.	
Section 3 Applicability	Load Serving Entity, Planning Authority and Resource Planner	II.D.M3 Applicable to	Entities required to report actual and forecast demand data.	
Section 3 Requirements	R3-1. (No translation attempted)	Standard for  IIDM3       II.D. M3 Measurement   II.D.M3 Full (100%) Compliance Requirement	<p>S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.</p> <p>S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.</p> <p>M3. Actual and forecast customer demand data and controllable demand-side management data reported to government agencies shall be consistent with data reported to those entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC</p> <p>The procedures shall require consistency in reporting actual and forecast demands and controllable demand-side management data for reliability purposes and to government agencies.</p>	<p>The content of S1 and S2 are repeated and detailed more completely in the M3 measurement and therefore not used directly in translation.</p> <p>Full (100%) Compliance Requirement does not agree with Measurement M3 and therefore no translation was attempted.</p>
Section 3 Measures	M3-1 (No translation attempted)	II.D.M3 Items to be Measured	Procedures requiring consistency of data reported for reliability purposes and to government agencies.	Items to be Measured do not agree with Measurement M3 and therefore no translation was attempted.
Section 3 Regional	None identified	None	None identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Differences				
Section 3 Compliance Monitoring Process	Regional Reliability Council  Annually or as specified in the documentation (Reliability Standard 061-R1-1)	II.D.M3 Compliance Monitoring Responsibility  II.D.M3 Timeframe	Regions  Annually or as specified in the documentation (Standard II.D. S1-S2, M1)	No translation was attempted due to above inconsistency
Section 3 Levels of Non Compliance	(No translation attempted)	II.D.M3 Levels of Non- Compliance	Level 1 - Consistent demand data was provided on schedule, but was incomplete in one or more areas.  Level 2 - Consistent demand data was not provided on schedule, but was complete when submitted.  Level 3 - Consistent demand data was not provided on schedule, and was incomplete in one or more areas when submitted.  Level 4 - Consistent demand data was not provided	No translation was attempted due to above inconsistency
Section 4	Aggregated actual and forecast demands and net energy for load	Brief Descriptions II.D.M4	Aggregated actual and forecast demands and net energy for load	
Section 4 Applicability	Load Serving Entity, Planning Authority and Resource Planner.	II.D.M4 Applicable to	Entities required by the Region to report actual and forecast demand data.	Incorporated Functional Model terminology
Section 4 Requirements		Standard for II.D.M4	S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power	The content of S1 related to this section is repeated and detailed more completely in the M4 measurement and

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R4-1. Load Serving Entity, Planning Authority and Resource Planner shall provide the following information annually on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard 061, Section 1.</p> <ol style="list-style-type: none"> <li>1. Integrated hourly demands in megawatts (MW) for the prior year.</li> <li>2. Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.</li> <li>3. Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.</li> <li>4. Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh for at least five years and up to ten years into the future, as requested</li> </ol>	II.D.M4 Measurement	<p>pool, and individual system basis and on a dispersed substation basis.</p> <p>M4. The following information shall be provided annually on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D. S1-S2, M1.</p> <ol style="list-style-type: none"> <li>1. Integrated hourly demands in megawatts (MW) for the prior year.</li> <li>2. Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.</li> <li>3. Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.</li> <li>4. Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh for at least five years and up to ten years into the future, as requested</li> </ol>	<p>therefore not used directly in translation.</p> <p>M4 was modified to incorporate functional model terminology.</p> <p>Reference to II.D. S1-S2, M1 was replaced with “Standard 061, Section 1”.</p>
Section 4 Measures	M4-1 Load Serving Entity, Planning Authority and Resource Planner shall provide evidence that it provided load data per Standard 061 R4-1.	II.D.M4 Items to be Measured	Aggregated actual and forecast demand and net energy for load data	Added words “provide evidence” to the language to make a measurable standard.
Section 4 Regional Differences	None identified	None	None identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 4 Compliance Monitoring Process	Regional Reliability Council  Annually or as specified in the documentation (Standard 061, Section 1)	II.D.M4 Timeframe  Compliance Monitoring Responsibility	Annually or as specified in the documentation (Standard II.D. S1-S2, M1) Regions.	Combined compliance monitoring responsibility and timeframe and changed “Standard” reference to Version 0
Section 4 Levels of Non Compliance	<p>Level 1 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in one of the four areas as required in the above Measurement M4.</p> <p>Level 2 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in two of the four areas as required in the above Measurement M4.</p> <p>Level 3 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in three of the four areas as required in the above Measurement M4.</p> <p>Level 4 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in any of the areas as required in the above Measurement M4.</p>	II.D.M4  Levels of non-compliance	<p>Level 1 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in one of the four areas as required in the above Measurement M4.</p> <p>Level 2 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in two of the four areas as required in the above Measurement M4.</p> <p>Level 3 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in three of the four areas as required in the above Measurement M4.</p> <p>Level 4 - Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in any of the areas as required in the above Measurement M4.</p>	No changes
Section 5	Treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.	II.D.M6 Brief Descriptions	Treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.	
Section 5	Load Serving Entity, Planning Authority and Resource Planner.	II.D.M6 Applicable to	Entities required by the Region to report actual and forecast	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Applicability			demand data.	
Section 5 Requirements	<p>R5-1. Load Serving Entity, Planning Authority and Resource Planner actual and forecast demand data reported on either an aggregated or dispersed basis shall:</p> <ol style="list-style-type: none"> <li>1. indicate whether the demand data of nonmember entities within an area or Regional Reliability Council are included, and</li> <li>2. address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and net energy for load.</li> </ol> <p>Full compliance requires items (1) and (2) to be addressed as described in the reporting procedures developed for Standard 061, Section 1.</p> <p>R5-2. Load Serving Entity, Planning Authority and Resource Planner shall report data associated with Requirement R5-1 to NERC, the Regional Reliability Council, Load Serving Entity, Planning Authority, and Resource Planner on request (within 30 days).</p>	<p>Standard for II.D.M6</p> <p>II.D.M6 Measurement</p>	<p>S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.</p> <p>M6. The actual and forecast demand data reported on either an aggregated or dispersed basis shall:</p> <ol style="list-style-type: none"> <li>a) indicate whether the demand data of nonmember entities within an area or Region are included, and</li> <li>b) address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and net energy for load.</li> </ol> <p>Full compliance requires items (a) and (b) to be addressed as described in the reporting procedures developed for Measurement M1 of this Standard II.D. Current information on items a) and b) shall be reported to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request (within 30 days).</p>	<p>The content of S1 related to this section is repeated and detailed more completely in the M6 measurement and therefore not used directly in translation.</p> <p>M6 was modified to incorporate functional model terminology.</p> <p>Reference to II.D. S1-S2, M1 was replaced with “Standard 061, Section 1”.</p>
Section 5	M5-1 Load Serving Entity, Planning Authority and Resource Planner shall provide evidence that its actual and	II.D.M6 Items to be	a) Treatment of actual and forecast demand data of	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Measures	<p>forecast demand data was addressed as described in the reporting procedures developed for Reliability Standard 061, Section 1.</p> <p>M5-2 Load Serving Entity, Planning Authority and Resource Planner shall report current information for Reliability Standard 061-R5 -1 to NERC, the Regional Reliability Council, Load Serving Entity, Planning Authority, and Resource Planner on request (within 30 days).</p>	Measured	<p>nonmember entities.</p> <p>b) Information on assumptions, methods, and how uncertainties are addressed in the forecasts of demand and net energy for load data.</p>	
Section 5 Regional Differences	None identified		None identified	
Section 5 Compliance Monitoring Process	<p>On Request (within 30 days)</p> <p>Regional Reliability Councils</p>	<p>II.D.M6 Timeframe</p> <p>II.D.M6 Compliance Monitoring Responsibility</p>	<p>On Request (within 30 days)</p> <p>Regions.</p>	Combined compliance monitoring responsibility and timeframe and changed “Standard” reference to Version 0
Section 5 Levels of Non Compliance	<p>Level 1 - Information on items a) or b) was not provided.</p> <p>Level 2 - Information on items a) and b) was not provided.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Not applicable.</p>	II.D.M6 Levels of non-compliance	<p>Level 1 - Information on items a) or b) was not provided.</p> <p>Level 2 - Information on items a) and b) was not provided.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Not applicable.</p>	
Section 6	Reporting of interruptible demands and direct control load	II.D.M10 Brief	Reporting of interruptible demands and direct control load	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	management.	Descriptions	management.	
Section 6 Applicability	Load Serving Entity, Planning Authority and Resource Planner.	II.D.M10 Applicable to	Entities required by the Region to report actual and forecast demand data.	
Section 6 Requirements	R6-1 Forecasts of interruptible demands and direct control load management data shall be provided annually for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regions, and other entities (Load Serving Entity, Planning Authority and Resource Planner) as specified by the documentation in Reliability Standard 061, Section 1.	Standard for II.D.M10  II.D.M10 Measurement	S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.  M10. Forecasts of interruptible demands and direct control load management data shall be provided annually for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D. S1-S2, M1.	Reference to II.D. S1-S2, M1 was replaced with “Standard 061, Section 1”.
Section 6 Measures	M6-1 Load Serving Entity, Planning Authority and Resource Planner shall provide evidence that they provided forecasts of interruptible demands and direct control load management data per Reliability Standard 061 R6-1.	II.D.M10 Items to be Measured	Interruptible demands and direct control load management data.	
Section 6 Regional Differences	None identified		None identified	
Section 6 Compliance Monitoring	Annually or as specified in the documentation (Reliability	II.D.M10 Timeframe	Annually or as specified in the documentation (Standard	Combined compliance monitoring responsibility and timeframe and changed

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Process	Standard 061, Section 1)  Each Regional Reliability Council	II.D.M10 Compliance Monitoring Responsibility	II.D. S1-S2, M1).  Regions.	“Standard” reference to Version 0
Section 6 Levels of Non Compliance	Level 1 – Not applicable  Level 2 – Not applicable  Level 3 – Not applicable  Level 4 - The Load Serving Entity, Planning Authority or Resource Planner did not provide the controlled demand-side management data as required in Standard 061, Section 1, above.	II.D.M10 Levels of non- compliance	Level 1 – Not applicable  Level 2 – Not applicable  Level 3 – Not applicable  Level 4 - The reporting entity did not provide the controlled demand-side management data as required in the above Measurement M1.	Incorporated Functional Model Terminology.
Section 7	Providing interruptible demands and direct control load management data to system operators and security center coordinators.	II.D.M11 Brief Description	Interruptible demands and direct control load management data to be made known to system operators and security center coordinators.	
Section 7 Applicability	Load Serving Entity, Planning Authority and Resource Planner	II.D.M11 Applicable to	Entities required by the Region to report actual and forecast demand data.	
Section 7 Requirements	R7-1 The Load Serving Entity, Planning Authority and Resource Planner shall be made known its amount of interruptible demands and direct control load management to system operators and security center coordinators on request within 30 days.	II.D.M11 Standard II.D.M11 Measure	S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.  M11. The amount of interruptible demands and direct control load management shall be made known to system operators and security center coordinators on request.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			Full compliance requires the reporting of this data to system operators and security center coordinators within 30 days of a request.	
Section 7 Measures	M7-1 The Load Serving Entity, Planning Authority and Resource Planner made known its amount of interruptible demands and direct control load management to system operators and security center coordinators on request within 30 days	II.D.M11 Items to be measured	Reporting of interruptible demands and direct control load management data to system operators and security center coordinators	
Section 7 Regional Differences	None identified	None	None identified	
Section 7 Compliance Monitoring Process	On request (within 30 days).  Regional Reliability Council	II.D.M11 Timeframe  II.D.M11 Compliance Monitoring Responsibility	On request (within 30 days).  Regions.	
Section 7 Levels of Non Compliance	Level 1 Interruptible demands and direct control load management data were provided to system operators and security center coordinators, but were incomplete.  Level 2 Not applicable.  Level 3 Not applicable.  Level 4 Interruptible demands and direct control load management data were not provided to system operators and	II.D.M11 Levels of Noncompliance	Level 1 Interruptible demands and direct control load management data were provided to system operators and security center coordinators, but were incomplete.  Level 2 Not applicable.  Level 3 Not applicable.  Level 4 Interruptible demands and direct control load management data were not provided to system operators and	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	security center coordinators.		security center coordinators.	
Section 8	Documentation of the accounting methodology for the effects of controllable demand-side management in demand and energy forecasts.	II.D.M12 Brief Description	Documentation of the method of accounting for the effects of controllable demand-side management in demand and energy forecasts.	
Section 8 Applicability	Load Serving Entity, Planning Authority and Resource Planner	II.D.M12 Applicable to	Entities required by the Region to report actual and forecast demand data.	Incorporated Functional Model terminology
Section 8 Requirements	<p>R8-1 The Load Serving Entity, Planning Authority and Resource Planner forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.</p> <p>R8-2 The Load Serving Entity, Planning Authority and Resource Planner information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load shall be included in the data reporting procedures of Standard 061-R1-1.</p> <p>R8-3 The Load Serving Entity, Planning Authority and Resource Planner documentation on the treatment of demand-side management programs shall be available to NERC on request (within 30 days).</p>	II.D.M12 Standard II.D.M12 Measure	<p>S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.</p> <p>M12. Forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.</p> <p>Information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load shall be included in the data reporting procedures of Measurement M1 of this Standard II.D. Documentation on the treatment of demand-side management programs shall be available to NERC on request (within 30 days).</p>	<p>Incorporated Functional Model terminology</p> <p>Divided M12 into three Requirements</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 8 Measures	<p>M8-1 The Load Serving Entity, Planning Authority and Resource Planner forecasts clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.</p> <p>M8-2 The Load Serving Entity, Planning Authority and Resource Planner information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load are included in the data reporting procedures of Reliability Standard 061-R1-1.</p> <p>M8-3 The Load Serving Entity, Planning Authority and Resource Planner provided evidence that it provided documentation on the treatment of demand-side management programs to NERC as requested (within 30 days).</p>	II.D.M12 Items to be measured	How the effects of demand-side management programs are addressed in the forecasts of peak demand and annual net energy for load.	
Section 8 Regional Differences	None identified	None	None identified	
Section 8 Compliance Monitoring Process	<p>On request (within 30 days).</p> <p>Regional Reliability Council</p>	<p>II.D.M12 Timeframe</p> <p>II.D.M12 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days).</p> <p>Regions.</p>	
Section 8 Levels of Non Compliance	Level 1 Documentation on the treatment of demand-side management programs in the demand and energy forecasts was provided, but was incomplete.	II.D.M12 Levels of Noncompliance	Level 1 Documentation on the treatment of demand-side management programs in the demand and energy forecasts was provided, but was incomplete.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 Documentation on the treatment of demand-side management programs in the demand and energy forecasts was not provided.</p>		<p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 Documentation on the treatment of demand-side management programs in the demand and energy forecasts was not provided.</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	062	Compliance Templates II.E.M1 II.E.M2 II.E.M3	II. System Modeling Data Requirements  E. Demand characteristics (Dynamic)	
Title	Load Models for System Dynamics Studies	Section	II. System Modeling Data Requirements  E. Demand characteristics (Dynamic)	
Purpose	Ensure accurate frequency and voltage characteristics of customer demands (models of loads for dynamics studies) required for the analysis of the reliability of the interconnected transmission system.			
Effective Date	February 8, 2005	Approval Dates	II.E.M1 – Engineering Committee July 14, 1998 II.E.M2 - Engineering Committee July 14, 1998 II.E.M3 - Engineering Committee July 14, 1998	
Standard Applicability	Section 1 - Regional Reliability Council, Planning Authority  Section 2 - Regional Reliability Council, NERC System Dynamics Database Working Group  Section 3 – Load-serving Entity	Applicability	M1 - The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions  M2 - Systems Dynamics Database Working Group (Eastern Interconnection), and the Western, ERCOT, and <b>Hydro-Québec</b> Interconnections.  M3 - Load Serving Entities	
Section 1	Customer (dynamic) demand characteristics to be determined and reported for reliability analyses.	II.E.M1 Brief Description	Customer (dynamic) demand characteristics to be determined and reported for reliability analysis	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 1 Applicability	Regional Reliability Council, Planning Authority	II.E.M1 Applicable to	The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions	
Section 1 Requirements	<p>R1-1 The Planning Authorities in conjunction with the Regional Reliability Council(s) shall develop a plan for determining and promoting the accuracy of the dynamic representation (e.g., frequency and voltage characteristics) of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting.</p> <p>R1-2. The Planning Authority shall provide documentation of these customer demand characteristics (dynamic) plans and reporting procedures to NERC and the Regional Reliability Councils on request (five business days).</p>	<p>II.E.M1 Standard</p> <p>II.E.M1 Measurement</p> <p>Full (100%) Compliance Requirement</p>	<p>S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.</p> <p>M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall develop a plan for determining and promoting the accuracy of the representation of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting. Documentation of these customer demand characteristics (dynamic) plans and reporting procedures shall be provided to NERC and the Regions on request.</p> <p>Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions, as appropriate, shall develop and maintain a plan for determining and promoting the accuracy of the dynamic representation (e.g., frequency and voltage characteristics) of customer demands in accordance with Measurements M1 and M2 of this Standard II.E. S1. This plan shall also include the procedures and scheduling for the</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			reporting of customer (dynamic) demand characteristics by load-serving entities. The documentation of this plan and procedures shall be available to the Regions and NERC on request (five business days).	
Section 1 Measures	<p>M1-1. The Planning Authority and the Regional Reliability Council shall have a plan for the evaluation and reporting of the voltage and frequency characteristics of customer demands</p> <p>M1-2 The Planning Authority and the Regional Reliability Council shall provide documentation of these customer demand characteristics and reporting procedures to the Regional Reliability Councils and NERC on request (five business days).</p>	II.E.M1 Items to be Measured	Plans for the evaluation and reporting of the voltage and frequency characteristics of customer demands.	
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	<p>On request (five business days).</p> <p>Regional Reliability Council and NERC</p>	<p>II.E.M1 Timeframe</p> <p>II.E.M1 Compliance Monitoring Responsibility</p>	<p>On request (five business days).</p> <p>Regions and NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided, but was complete when submitted.</p>	II.E.M1 Levels of Non-compliance	<p>Level 1 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was provided on schedule, but was incomplete in one or more areas.</p> <p>Level 2 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided, but was complete when</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided.</p>		<p>submitted.</p> <p>Level 3 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided.</p>	
Section 2	Requirements for determining customer (dynamic) demand characteristics to be included in procedural manuals.	II.E.M2 Brief Description	Requirements for determining customer (dynamic) demand characteristics to be included in procedural manuals.	
Section 2 Applicability	Regional Reliability Council, NERC System Dynamics Database Working Group	II.E.M2 Applicability	Systems Dynamics Database Working Group (Eastern Interconnection), and the Western, ERCOT, and <b>Hydro-Québec</b> Interconnections.	
Section 2 Requirements		II.E.M2 Standard	S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.	
		II.E.M2	M2. The NERC System Dynamics Database Working	

<sup>6</sup>Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R2-1 The Regional Reliability Councils, collectively on an Interconnection basis, shall maintain and publish customer demand characteristics requirements in its “procedural manual” pertaining to the Interconnection. For the Eastern Interconnection and Hydro-Quebec, the NERC System Dynamics Database Working Group or its successor group(s) shall work with the associated Regional Reliability Councils to maintain and publish customer demand characteristics requirements in its “procedural manual” pertaining to the Eastern Interconnection and the Hydro-Quebec Interconnection. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands.</p> <p>R2-2 Procedural manuals shall be available to the Regional Reliability Councils and NERC on request (five business days).</p>	<p>Measurements</p> <p>Full (100%) Compliance Requirements</p>	<p>Group or its successor group(s) shall maintain and publish customer demand characteristics requirements in its “procedural manual” pertaining to the Eastern Interconnection. Similar “procedural manuals” shall be maintained and published by the Western (WSCC), ERCOT, and Hydro-Québec<sup>6</sup> Interconnections. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands.</p> <p>Procedural manuals for the Eastern, Western, ERCOT, and Hydro-Quebec interconnections shall include the requirements for determining and promoting the accuracy of the dynamic representation of customer demands in accordance with Measurement M5 above and Measurements M4 and M5 of Standard II.A. These procedural manuals should be available to the Regions and NERC on request (five business days).</p>	
Section 2 Measures	M2-1 The Regional Reliability Council shall have a procedural manual containing plans for determining and promoting the accuracy of the representation of customer demands that contains all elements of Section 1 of Reliability Standard 062, Section 4 of Reliability Standard 058, and Section 5 of Reliability Standard 058.	II.E.M2 Items to be Measured	Documentation of requirements for determining dynamic characteristics of customer demands.	
Section 2 Regional Differences	None identified		None identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Compliance Monitoring Process	On request (five business days).  NERC	II.E.M2 Timeframe  II.E.M2 Compliance Monitoring Responsibility	On request (five business days).  NERC	
Section 2 Levels of Non Compliance	<p>Level 1 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided.</p>	II.E.M2  Levels of Non-compliance	<p>Level 1 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided.</p>	
Section 3	Load-serving entities to provide customer (dynamic) demand characteristics.	II.E.M3 <u>Brief</u> <u>Description</u>	Load-serving entities to provide customer (dynamic) demand characteristics.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 3 Applicability	Load Serving Entity	II.E.M3 Applicability	Load Serving Entities	
Section 3 Requirements	<p>R3-1 The Load-Serving Entity shall provide customer demand characteristics to the Regional Reliability Councils and Planning Authorities in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.<sup>7</sup></p>	<p>II.E.M3 Standard</p> <p>II.E.M3 Measurement</p> <p>Full (100%) Compliance Requirement</p>	<p>S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.</p> <p>M3. Load-serving entities shall provide customer demand characteristics to the Regions and those entities responsible for the reliability of the interconnected transmission systems in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.<sup>7</sup></p> <p>Load-serving entities shall provide customer demand characteristics in accordance with Measurement M3 above and the procedural manuals of Measurement M2 of this Standard II.E.</p>	
Section 3 Measures	M3-1 The Load-Serving Entity shall have evidence that it provided customer demand dynamic characteristics (Load Models) in accordance with Section 2 of Reliability Standard 062.	II.E.M3 Items to be Measured	Customer (dynamic) demand characteristics.	
Section 3 Regional Differences	None identified		None identified	
Section 3	As specified in the documentation (Standard 062-R2-1)	II.E.M3	As specified in the documentation (Standard II.E. S1, M1-	

<sup>7</sup> Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Compliance Monitoring Process	Regional Reliability Council	Timeframe  II.E.M3 Compliance Monitoring Responsibility	M2).  Regions	
Section 3 Levels of Non Compliance	Level 1 - Customer demand (dynamic) characteristics were provided on schedule, but were incomplete in one or more areas.  Level 2 - Customer demand (dynamic) characteristics were not provided on schedule, but were complete when submitted.  Level 3 - Customer demand (dynamic) characteristics were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Customer demand (dynamic) characteristics were not provided	II.E.M3  Levels of Non-compliance	Level 1 - Customer demand (dynamic) characteristics were provided on schedule, but were incomplete in one or more areas.  Level 2 - Customer demand (dynamic) characteristics were not provided on schedule, but were complete when submitted.  Level 3 - Customer demand (dynamic) characteristics were not provided on schedule, and were incomplete in one or more areas when submitted.  Level 4 - Customer demand (dynamic) characteristics were not provided	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	063	Compliance Template III.A.M3 III.A.M4 III.A.M5	III. System Protection and Control  A. Transmission Protection Systems	Current Planning Standards IIIA S3 M3 and M5  Some statements from the Standards and Compliance Templates have been rewritten to incorporate the Functional Model terminology and speak in “active voice”
Title	Transmission Protection System	Section	III. System Protection and Control A. Transmission Protection Systems	
Purpose	To ensure all transmission protection system misoperations are analyzed for cause and corrective action and maintenance and testing programs are developed and implemented.	Standard for III.A.M3 III.A.M4 III.A.M5		Purpose derived from Standard S3 and S4
Effective Date	February 8, 2005	Approvals	III.A.M3 - BOT Approved February 20, 2002 III.A.M4 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 III.A.M5 - BOT Approved February 20, 2002	
Standard Applicability	Section 1: Regional Reliability Council  Section 2: Transmission Owner and Generator Owner  Section 3: Transmission Owner and Generator Owner	Applicable to III.A.M3  III.A. M4  III.A.M4	M3 – Regions  M4 - Transmission protection system owners  M5 - Transmission protection system owners	Incorporated functional model terminology
Section 1	Regional Procedure for Transmission Protection system misoperations.	III.A.M3 Brief Description	(none identified)	New section title
Section 1 Applicability	Regional Reliability Council	III.A.M3 Applicable to	Regions	Incorporated functional

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
				model terminology
Section 1 Requirements	<p>R1-1. Each Regional Reliability Council shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. Each Regional Reliability Council’s procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring and analysis of all transmission protective device misoperations.</li> <li>2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affects the reliability of the bulk electric systems as specified by the Regional Reliability Council.</li> <li>3. Process for review, follow up, and documentation of corrective action plans for misoperations.</li> <li>4. Identification of the Regional Reliability Council group responsible for the procedure and the process for Regional Reliability Council approval of the procedure.</li> <li>5. Regional Reliability Council definition of misoperations.</li> </ol> <p>R1-2. Each Regional Reliability Council shall maintain documentation of its procedure and provide it to NERC on request (within 30 days).</p>	<p>III.A.M3 Standard  III.A.M3 Measure</p>	<p>S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.</p> <p>M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring and analysis of all transmission protective device misoperations.</li> <li>2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.</li> <li>3. Process for review, follow up, and documentation of corrective action plans for misoperations.</li> <li>4. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.</li> <li>5. Regional definition of misoperations.</li> </ol> <p>Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30</p>	<p>R1-1 restates M3 incorporating functional model terminology</p> <p>R1-2 restates the last paragraph of M3</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			days).	incorporating functional model terminology
Section 1 Measures	<p>M1-1. The Regional Reliability Council shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations as defined in Standard 063-R1-1.</p> <p>M1-2. The Regional Reliability Council shall have evidence it provided documentation of its procedure as defined in Standard 063-R1-2.</p>	III.A.M3 Items to be Measured	Procedure for monitoring, review, analysis, and correction of all transmission protection system misoperations	Suggested measures for Requirements R1-1 and R1-2
Section 1 Regional Differences	Not identified		Not identified	No known regional differences
Section 1 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>NERC</p>	<p>III.A.M3 Timeframe</p> <p>III.A.M3 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 The Regional Reliability Council’s procedure does not address all the requirements as defined above in Standard 063-R1-1.</p> <p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 The Regional Reliability Council’s procedure was not</p>	III.A.M3 Levels of Compliance	<p>Level 1 The Regional procedure does not address all the requirements as defined above in Measurement M3.</p> <p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 The Regional procedure was not provided.</p>	Incorporated functional model terminology and changed references to match the requirements used in the new standard.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	provided.			
Section 2	Analysis and Reporting of Transmission Protection System Misoperations	III.A. M5 Brief Description	Analysis and reporting of transmission protection system mis-operations	New section title
Section 2 Applicability	Transmission Owners, Generator Owners, Distribution Providers	III.A. M5 Applicable to	Transmission protection system owners	Incorporated functional model terminology
Section 2 Requirements	<p>R2-1. The Transmission Owner, Generator Owner, Distribution Provider that owns transmission protection system(s) shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.</p> <p>R2-2. The Transmission Owner, Generator Owner, Distribution Provider that owns transmission protection system(s) shall provide to the affected Regional Reliability Council and NERC on request (within 30 days) documentation of the misoperations analyses and corrective actions according to the Regional Reliability Council’s procedures of Standard 063-R1-1.</p>	<p>III.A.M5 Standard</p> <p>III.A. M5 Measure</p>	<p>S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.</p> <p>M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.</p> <p>Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.</p>	<p>R2-1 restates M5 incorporating functional model terminology</p> <p>R1-2 restates the last paragraph of M5 incorporating functional model terminology and changed reference to the requirements of the new standard.</p>
Section 2 Measures	<p>M2-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns transmission protection system(s) shall have evidence it analyzed its protection system misoperation(s) and took corrective action(s) to avoid future misoperations.</p> <p>M2-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns transmission protection system(s) shall have evidence it provided documentation of its protection system misoperations, analyses and corrective action(s) according to the Regional Reliability Council</p>	III.A. M5 Items to be Measured	Documentation of protection system misoperations, analyses, and corrective actions.	Suggested measures for Requirements R2-1 and R2-2

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	procedures of Standard 063-R1-1.			
Section 2 Regional Differences	Not identified		Not identified	No known regional differences
Section 2 Compliance Monitoring Process	On request (within 30 days)  Regional Reliability Council	III.A.M5 Timeframe  III.A.M5 Compliance Monitoring Responsibility	On request (within 30 days)  Regions	Incorporated functional model terminology
Section 2 Levels of Non Compliance	Level 1— Documentation of transmission protection system misoperations is complete according to Standard 063-R1-1 but documentation of corrective actions taken for all identified misoperations is incomplete.  Level 2 – Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Standard 063-R1-1.  Level 3 – Documentation of misoperations and corrective actions is incomplete.  Level 4 – No documentation of misoperations or corrective actions was provided.	III.A.M5 Levels of Compliance	Level 1 Documentation of transmission protection system misoperations is complete according to Measurement III.A. S3, M3 but documentation of corrective actions taken for all identified misoperations is incomplete.  Level 2 Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Measurement III.A. S3, M3  Level 3 Documentation of misoperations and corrective actions is incomplete.  Level 4 No documentation of misoperations or corrective actions was provided.	Incorporated functional model terminology and changed references to match the requirements used in the new standard.
Section 3	Transmission Maintenance and Testing	III.A.M4 Brief Description	Transmission Maintenance and Testing	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Applicability	Transmission Owner and Generator Owner	III.A.M4 Applicable to	Transmission protection system owner	Applicability
Section 3 Requirements	<p>R3-1. The Transmission Owner and Generator Owner that owns transmission protection system(s) shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Transmission Protection system identification shall include but are not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing intervals and their basis</li> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>R3-2. The Transmission Owner and Generator Owner that owns transmission protection system(s) shall provide documentation of the program and its implementation to the appropriate Regional Reliability Council and NERC on request (within 30 days).</p>	<p>III.A.M4 Standard</p> <p>III.A. M4 Measure</p>	<p>S4. Transmission protection system maintenance and testing programs shall be developed and implemented.</p> <p>M4. Transmission protection system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Transmission Protection system identification shall include but are not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing intervals and their basis</li> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).</p>	<p>R1 restates M4 incorporating functional model terminology</p> <p>R2 restates the last paragraph of M4 incorporating functional model terminology</p>
Section 3 Measures	M3-1. The Transmission Owner or Generator Owner that owns a transmission system protection system(s) has a system shall have a maintenance and testing program(s) as defined in Standard 063-R3-1.	III.A.M4 Items to be Measured	Documentation and implementation of transmission protection system maintenance and testing program.	Suggested measures for Requirements R1 and R2.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	M3-2. The Transmission Owner and Generator Owner that owns transmission system protection system(s) shall have evidence it provided documentation of its system maintenance and testing program(s) and the implementation of its program(s) as defined in Standard 063-R3-2.			
Section 3 Regional Differences	Not identified		Not identified	No known regional differences
Section 3 Compliance Monitoring Process	On request (within 30 days)  Regional Reliability Council. Each Regional Reliability Council shall report compliance and violations to NERC via the NERC Compliance Reporting process.	III.A.M4 Timeframe  III.A.M4 Compliance Monitoring Responsibility	On request (within 30 days)  Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.	Incorporated functional model terminology
Section 3 Levels of Non Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.	III.A.M4 Levels of Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.	Incorporated functional model terminology

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	063	Compliance Template III.A.M3 III.A.M4 III.A.M5	III. System Protection and Control  A. Transmission Protection Systems	Current Planning Standards IIIA S3 M3 and M5  Some statements from the Standards and Compliance Templates have been rewritten to incorporate the Functional Model terminology and speak in “active voice”
Title	Transmission Protection System	Section	III. System Protection and Control A. Transmission Protection Systems	
Purpose	To ensure all transmission protection system misoperations are analyzed for cause and corrective action and maintenance and testing programs are developed and implemented.	Standard for III.A.M3 III.A.M4 III.A.M5		Purpose derived from Standard S3 and S4
Effective Date	February 8, 2005	Approvals	III.A.M3 - BOT Approved February 20, 2002 III.A.M4 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 III.A.M5 - BOT Approved February 20, 2002	
Standard Applicability	Section 1: Regional Reliability Council  Section 2: Transmission Owner and Generator Owner  Section 3: Transmission Owner and Generator Owner	Applicable to III.A.M3  III.A. M4  III.A.M4	M3 – Regions  M4 - Transmission protection system owners  M5 - Transmission protection system owners	Incorporated functional model terminology
Section 1	Regional Procedure for Transmission Protection system misoperations.	III.A.M3 Brief Description	(none identified)	New section title
Section 1 Applicability	Regional Reliability Council	III.A.M3 Applicable to	Regions	Incorporated functional

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
				model terminology
Section 1 Requirements	<p>R1-1. Each Regional Reliability Council shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. Each Regional Reliability Council’s procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring and analysis of all transmission protective device misoperations.</li> <li>2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affects the reliability of the bulk electric systems as specified by the Regional Reliability Council.</li> <li>3. Process for review, follow up, and documentation of corrective action plans for misoperations.</li> <li>4. Identification of the Regional Reliability Council group responsible for the procedure and the process for Regional Reliability Council approval of the procedure.</li> <li>5. Regional Reliability Council definition of misoperations.</li> </ol> <p>R1-2. Each Regional Reliability Council shall maintain documentation of its procedure and provide it to NERC on request (within 30 days).</p>	<p>III.A.M3 Standard</p> <p>III.A.M3 Measure</p>	<p>S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.</p> <p>M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring and analysis of all transmission protective device misoperations.</li> <li>2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.</li> <li>3. Process for review, follow up, and documentation of corrective action plans for misoperations.</li> <li>4. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.</li> <li>5. Regional definition of misoperations.</li> </ol> <p>Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30</p>	<p>R1-1 restates M3 incorporating functional model terminology</p> <p>R1-2 restates the last paragraph of M3</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			days).	incorporating functional model terminology
Section 1 Measures	<p>M1-1. The Regional Reliability Council shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations as defined in Standard 063-R1-1.</p> <p>M1-2. The Regional Reliability Council shall have evidence it provided documentation of its procedure as defined in Standard 063-R1-2.</p>	III.A.M3 Items to be Measured	Procedure for monitoring, review, analysis, and correction of all transmission protection system misoperations	Suggested measures for Requirements R1-1 and R1-2
Section 1 Regional Differences	Not identified		Not identified	No known regional differences
Section 1 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>NERC</p>	<p>III.A.M3 Timeframe</p> <p>III.A.M3 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 The Regional Reliability Council’s procedure does not address all the requirements as defined above in Standard 063-R1-1.</p> <p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 The Regional Reliability Council’s procedure was not</p>	III.A.M3 Levels of Compliance	<p>Level 1 The Regional procedure does not address all the requirements as defined above in Measurement M3.</p> <p>Level 2 Not applicable.</p> <p>Level 3 Not applicable.</p> <p>Level 4 The Regional procedure was not provided.</p>	Incorporated functional model terminology and changed references to match the requirements used in the new standard.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	provided.			
Section 2	Analysis and Reporting of Transmission Protection System Misoperations	III.A. M5 Brief Description	Analysis and reporting of transmission protection system mis-operations	New section title
Section 2 Applicability	Transmission Owners, Generator Owners, Distribution Providers	III.A. M5 Applicable to	Transmission protection system owners	Incorporated functional model terminology
Section 2 Requirements	<p>R2-1. The Transmission Owner, Generator Owner, Distribution Provider that owns transmission protection system(s) shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.</p> <p>R2-2. The Transmission Owner, Generator Owner, Distribution Provider that owns transmission protection system(s) shall provide to the affected Regional Reliability Council and NERC on request (within 30 days) documentation of the misoperations analyses and corrective actions according to the Regional Reliability Council’s procedures of Standard 063-R1-1.</p>	<p>III.A.M5 Standard</p> <p>III.A. M5 Measure</p>	<p>S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.</p> <p>M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.</p> <p>Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.</p>	<p>R2-1 restates M5 incorporating functional model terminology</p> <p>R1-2 restates the last paragraph of M5 incorporating functional model terminology and changed reference to the requirements of the new standard.</p>
Section 2 Measures	<p>M2-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns transmission protection system(s) shall have evidence it analyzed its protection system misoperation(s) and took corrective action(s) to avoid future misoperations.</p> <p>M2-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns transmission protection system(s) shall have evidence it provided documentation of its protection system misoperations, analyses and corrective action(s) according to the Regional Reliability Council</p>	III.A. M5 Items to be Measured	Documentation of protection system misoperations, analyses, and corrective actions.	Suggested measures for Requirements R2-1 and R2-2

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	procedures of Standard 063-R1-1.			
Section 2 Regional Differences	Not identified		Not identified	No known regional differences
Section 2 Compliance Monitoring Process	On request (within 30 days)  Regional Reliability Council	III.A.M5 Timeframe  III.A.M5 Compliance Monitoring Responsibility	On request (within 30 days)  Regions	Incorporated functional model terminology
Section 2 Levels of Non Compliance	Level 1— Documentation of transmission protection system misoperations is complete according to Standard 063-R1-1 but documentation of corrective actions taken for all identified misoperations is incomplete.  Level 2 – Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Standard 063-R1-1.  Level 3 – Documentation of misoperations and corrective actions is incomplete.  Level 4 – No documentation of misoperations or corrective actions was provided.	III.A.M5 Levels of Compliance	Level 1 Documentation of transmission protection system misoperations is complete according to Measurement III.A. S3, M3 but documentation of corrective actions taken for all identified misoperations is incomplete.  Level 2 Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Measurement III.A. S3, M3  Level 3 Documentation of misoperations and corrective actions is incomplete.  Level 4 No documentation of misoperations or corrective actions was provided.	Incorporated functional model terminology and changed references to match the requirements used in the new standard.
Section 3	Transmission Maintenance and Testing	III.A.M4 Brief Description	Transmission Maintenance and Testing	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Applicability	Transmission Owner and Generator Owner	III.A.M4 Applicable to	Transmission protection system owner	Applicability
Section 3 Requirements	<p>R3-1. The Transmission Owner and Generator Owner that owns transmission protection system(s) shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Transmission Protection system identification shall include but are not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing intervals and their basis</li> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>R3-2. The Transmission Owner and Generator Owner that owns transmission protection system(s) shall provide documentation of the program and its implementation to the appropriate Regional Reliability Council and NERC on request (within 30 days).</p>	<p>III.A.M4 Standard</p> <p>III.A. M4 Measure</p>	<p>S4. Transmission protection system maintenance and testing programs shall be developed and implemented.</p> <p>M4. Transmission protection system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Transmission Protection system identification shall include but are not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing intervals and their basis</li> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).</p>	<p>R1 restates M4 incorporating functional model terminology</p> <p>R2 restates the last paragraph of M4 incorporating functional model terminology</p>
Section 3 Measures	M3-1. The Transmission Owner or Generator Owner that owns a transmission system protection system(s) has a system shall have a maintenance and testing program(s) as defined in Standard 063-R3-1.	III.A.M4 Items to be Measured	Documentation and implementation of transmission protection system maintenance and testing program.	Suggested measures for Requirements R1 and R2.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	M3-2. The Transmission Owner and Generator Owner that owns transmission system protection system(s) shall have evidence it provided documentation of its system maintenance and testing program(s) and the implementation of its program(s) as defined in Standard 063-R3-2.			
Section 3 Regional Differences	Not identified		Not identified	No known regional differences
Section 3 Compliance Monitoring Process	On request (within 30 days)  Regional Reliability Council. Each Regional Reliability Council shall report compliance and violations to NERC via the NERC Compliance Reporting process.	III.A.M4 Timeframe  III.A.M4 Compliance Monitoring Responsibility	On request (within 30 days)  Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.	Incorporated functional model terminology
Section 3 Levels of Non Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.	III.A.M4 Levels of Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.	Incorporated functional model terminology

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	064	Compliance Templates I.D.M1 I.D.M2	I. System Adequacy and Security D. Voltage Support and Reactive Power	
Title	Voltage Support and Reactive Power	Section	I. System Adequacy and Security D. Voltage Support and Reactive Power	
Purpose	To ensure that reactive power resources, with a balance between static and dynamic characteristics, are planned and distributed throughout the interconnected transmission systems.			Language paraphrased from the original Planning Standard language of S1.
Effective Date	February 8, 2005	Approval Dates	Approved by the Engineering Committee for Field Testing in Phase IV, July 14, 1998	Approved as a Phase IV measurement.
Applicability	Section 1: Transmission Planner  Section 2: Transmission Planner, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator	Applicable to	I.D.M1: Entities Responsible for the Reliability of the Interconnected Transmission Systems  I.D.M2: Generation Owners and Transmission Providers	
Section 1	Adequate voltage resources to meet future customer demands.	I.D.M1 Brief Description	Adequate voltage resources to meet future customer demands.	
Section 1 Applicability	Transmission Planner	I.D.M1 Applicable to	Entities Responsible for the Reliability of the Interconnected Transmission Systems	Made applicable to Transmission Planners, since this requirement deals with an assessment of the system.
Section 1 Requirements	R1-1 Transmission Planners shall conduct assessments (at least every five years or as required by changes in system conditions) to	I.D.M1 Requirements	S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.  M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system	With the exception of “with a balance between static and dynamic characteristics,” the existing Planning Standard S1 was sufficiently captured in Measurement M1.  Measurement M1 translated in Requirement R1-1.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>ensure reactive power resources, with a balance between static and dynamic characteristics, are adequate to meet future system performance requirements (i.e., projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Sections 1, 2, and 3 of Reliability Standard 051).</p> <p>R1-2     The Transmission Planner’s assessment of reactive power resources shall address how known changes in system conditions may affect system reliability.</p> <p>R1-3     The Transmission Planner’s assessment of reactive power resources shall be conducted once every five years or as required by system conditions.</p> <p>R1-4     The Transmission Planner shall document its assessment of reactive power resources and shall provide these assessments to the Regional Reliability Councils and NERC on request.</p>		<p>conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems.</p> <p>Documentation of these assessments shall be provided to the Regions and NERC on request.</p>	<p>Requirements found under the “Full Compliance” section (below) were translated into Requirements R1-2 and R1-3.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 1 Measures	<p>M1-1 The Transmission Planner’s assessment of reactive power resources shall ensure that adequate reactive resources are available to meet future system performance requirements, and shall demonstrate that system performance is consistent with the system performance requirements as defined in Sections 1, 2, and 3 of Reliability Standard 51.</p> <p>M1-2 The Transmission Planner’s assessment of reactive power resources shall address how known changes in system conditions may affect system reliability.</p> <p>M1-3 The Transmission Planner shall have evidence it conducted an assessment of its reactive power resources within the past five years or as required by system conditions.</p> <p>M1-4 The Transmission Planner shall have evidence it provided documentation of the current assessment results to the Regional Reliability Council and NERC on request (within 30 business days).</p>	<p>I.D.M1 Items to be Measured</p> <p>I.D.M1 Full (100%) Compliance Requirements</p>	<p>Assessment of reactive power resources.</p> <p>The entities shall assess reactive power resources to ensure that adequate reactive resources are available to meet future system performance requirements. These assessment shall demonstrate that system performance is consistent with Categories A, B, and C of Table I of Standard I.A. Additionally, the assessments should address how known changes in system conditions may affect system reliability. These assessments shall be conducted every five years or as required by system conditions. The current assessment results shall be provided to the Regions and NERC on request (within 30 days).</p>	Added “business” to clarify reporting requirement.
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p>Every five years or as required by system conditions.</p> <p>Regional Reliability Council</p>	<p>Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Every five years or as required by system conditions.</p> <p>Regions</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - Assessments of reactive power resources were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Assessments of reactive power resources were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Assessments of reactive power resources were not provided on schedule, and were incomplete in one or more areas</p>	<p>I.D.M1</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - Assessments of reactive power resources were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Assessments of reactive power resources were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Assessments of reactive power resources were not</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>when submitted.</p> <p>Level 4 - Assessments of reactive power resources were not provided.</p>		<p>provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Assessments of reactive power resources were not provided.</p>	
Section 2	Coordinate and optimize the use of generator reactive capability.	I.D.M2 Brief Description	Coordinate and optimize the use of generator reactive capability.	
Section 2 Applicability	Generator Owner and Transmission Planner	I.D.M2 Applicable to	Generation Owners and Transmission Providers	Made applicable to Transmission Planners, since this requirement deals with an assessment of the system.
Section 2 Requirements	<p>R2-1 The Transmission Planner and Generator Owner shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:</p> <ul style="list-style-type: none"> <li>a. Coordination of generator step-up transformer impedance and tap specifications and settings,</li> <li>b. Calculation of underexcited limits based on machine thermal and stability considerations, and</li> <li>c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges.</li> </ul> <p>R2-2 The Transmission Planner shall document an assessment of the coordinated efforts outlined in Reliability Standard 064-R2-1, when all required data has been received from the Generator Owner(s), and at least every five years thereafter (or when warranted by changes in generation equipment or system conditions).</p> <p>R2-3 The Transmission Planner shall provide documentation of its assessments regarding the optimization of generator reactive</p>	I.D.M2 Requirements	<p>M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:</p> <ul style="list-style-type: none"> <li>a. Coordination of generator step-up transformer impedance and tap specifications and settings,</li> <li>b. Calculation of underexcited limits based on machine thermal and stability considerations, and</li> <li>c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges.</li> </ul>	<p>Some portions (e.g., R2-2) of the requirements are taken from the 100% Full Compliance section below, such as the documentation of an assessment by the Transmission Planner (Provider).</p> <p>The 30-day requirement for submittal of information also comes from the 100% Full Compliance Section, below.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	power capability to the Regional Reliability Councils and NERC on request (within 30 business days).			
Section 2 Measures	M2-1 The Transmission Planner’s and Generator Owner’s assessment regarding optimization of the use of generator reactive power capability shall cover the required components of Reliability Standard 064-R2-1..	I.D.M2 Items to be Measured	Generator reactive power capability	
	M2-2 The Transmission Planner shall have evidence it conducted an assessment regarding optimization of the use of generator reactive power capability within the past five years or as required by system conditions.	I.D.M2 Full (100%) Compliance Requirements	Transmission providers and generator owners shall coordinate on optimizing the amount of generator reactive power capability available for use by the transmission network. These efforts should address items such as generator step-up transformers impedance, transformer tap specifications and settings, as well as the calculation of underexcited limits, and other generator thermal and stability considerations.	
	M2-3 The Transmission Planner shall have evidence it provided documentation of its current assessment results to the Regional Reliability Council and NERC on request (within 30 business days).		Transmission providers should generally perform an initial coordination assessment when all required data has been received from the generator owners. Follow-on coordination assessments should be performed at least every five years or when warranted by changes in generation equipment or system conditions. The current assessment results shall be provided to the Regions and NERC on request (within 30 days).	
Section 2 Regional Differences	None identified.		None identified.	
Section 2 Compliance Monitoring Process	Every five years or as required by changes in generator equipment or system conditions.	Timeframe	Every five years or as required by changes in generator equipment or system conditions.	
	Regions	Compliance Monitoring Responsibility	Regions	
Section 2 Levels of Non Compliance	Level 1 - Assessments for the optimum use of generator reactive capability were provided on schedule, but were incomplete in one or more areas.	I.D.M2 Levels of Non-Compliance	Level 1 - Assessments for the optimum use of generator reactive capability were provided on schedule, but were incomplete in one or more areas.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 2 - Assessments for the optimum use of generator reactive capability were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Assessments for the optimum use of generator reactive capability were not provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Assessments for the optimum use of generator reactive capability were not provided.</p>		<p>Level 2 - Assessments for the optimum use of generator reactive capability were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Assessments for the optimum use of generator reactive capability were not provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Assessments for the optimum use of generator reactive capability were not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	065	Compliance Templates III.C.M1 III.C.M2 III.C.M3 III.C.M4 III.C.M5 III.C.M6 III.C.M7 III.C.M8 III.C.M9 III.C.M10 III.C.M11 III.C.M12	III. System Protection and Control C. Generation Control and Protection Measurements M1-M12	
Title	Generation Control and Protection	Section	III. System Protection and Control C. Generation Control and Protection	
Purpose	To ensure that generation control and protection systems are planned and designed to provide a balance between the need for generation to support the electrical system and the need to protect generation equipment and to ensure that generation control and protection equipment is accurately modeled in system reliability studies			.
Effective Date	February 8, 2005 all Sections	Approval dates	III.C.M1-12 effective October 9, 2000  Phase III	
Standard Applicability	Section 1 Transmission Operator Section 2 Generator Operator Section 3 Transmission Operator Section 4 Generator Owner Section 5 Transmission Operator Section 6 Generator Owner	Applicable to	III.C.M1 Transmission System Operators III.C.M2 Generation owners/operators III.C.M3 Transmission System Operators III.C.M4 Generation owners/operators III.C.M5 Transmission System Operators III.C.M6 Generation owners/operators	To clarify accountability, responsibility was assigned to either Generator Owner or Generator Operator as

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Section 7 Regional Reliability Council Section 8 Generator Owner Section 9 Generator Owner Section 10 Regional Reliability Council Section 11 Generator Owner Section 12 Generator Owner		III.C.M7 Regions III.C.M8 Generation owners/operators III.C.M9 Generation owner/operator III.C.M10 Regions III.C.M11 Generation owner/operator III.C.M12 Generation owner/operator	considered appropriate
Section 1	Operation of all synchronous generators in the automatic voltage control mode.	III.C.M1 Brief Description	Operation of all synchronous generators in the automatic voltage control mode.	
Section 1 Applicability	Transmission Operator	III.C.M1 Applicable to	Transmission System Operators	
Section 1 Requirements	R1-1. The Transmission Operator shall have procedures requiring Generator Operator to provide the following information to them, the Regional Reliability Council, and NERC on request (five business days): <ul style="list-style-type: none"> <li>a. Summary reports showing the number of hours each synchronous generator did not operate in the automatic voltage control mode during a specified time period, and</li> <li>b. Detailed reports of the date, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode.</li> </ul> R1-2. The procedures shall require the Generator Operator to retain the above information for 12 rolling months.  R1-3. The procedures shall also specify criteria by which generators are to be exempt from the above	III.C.M1 Standards and Measurements	S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the Transmission Operator.  M1. Transmission Operators shall have procedures requiring synchronous generator owners/operators to provide the following information to them, the Region, and NERC on request (five business days): <ul style="list-style-type: none"> <li>a. Summary reports showing the number of hours each synchronous generator did not operate in the automatic voltage control mode during a specified time period, and</li> <li>b. Detailed reports of the date, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode.</li> </ul>	The Functional Model assigns to the Generator Operator the responsibility of reporting of status of automatic voltage regulators to Transmission Operators



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	requirements.		<p>The procedures shall require the generator owner/operator to retain the above information for 12 rolling months.</p> <p>The procedures shall also specify criteria by which generators are to be exempt from the above requirements.</p>	
Section 1 Measures	M1-1. The Transmission Operator has evidence that the written procedures for synchronous generators meet Reliability Standard 065-R1-1 to 065-R1-3.	III.C.M1 Items to be measured	Documentation of procedures for reporting when a synchronous generator is operated without automatic voltage control equipment in service.	
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	<p>On request (five business days).</p> <p>Regional Reliability Council</p>	<p>III.C.M1 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (five business days).</p> <p>Regions</p>	
Section 1 Levels of Non Compliance	<p>Level 1 - Transmission Operator has procedures for Generator Operators to follow but they do not include all of the requirements of above Requirements R1-1 to R1-3.</p> <p>Level 2 - N/A.</p> <p>Level 3 - N/A.</p> <p>Level 4 - Transmission Operator has no procedures for Generator Operator to follow to report generator operation in the non-automatic voltage control mode.</p>	III.C.M1 Levels of Non-Compliance	<p>Level 1 - Transmission Operator has procedures for synchronous generator owners/operators to follow but they do not include all of the requirements of above Measurement M1.</p> <p>Level 2 - N/A.</p> <p>Level 3 - N/A.</p> <p>Level 4 - Transmission Operator has no procedures for synchronous generator owners/operators to follow to report generator operation in the non-automatic voltage control mode.</p>	The Functional Model assigns to the Generator Operator the responsibility of reporting of status of automatic voltage regulators to Transmission Operators

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 2	Operation of all synchronous generators in the automatic voltage control mode.		III.C.M2 Brief Description	Operation of all synchronous generators in the automatic voltage control mode.	
Section 2 Applicability	Generator Operator		III.C.M2 Applicable to	Generation owners/operators	The Functional Model assigns to the Generator Operator the responsibility of reporting of status of automatic voltage regulators to Transmission Operators
Section 2 Requirements	R2-1	The Generation Operator shall operate each synchronous generating unit connected to the interconnected transmission system in the automatic voltage control mode unless otherwise approved by the Transmission Operator.	III.C.M2 Standard   		

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			Transmission Operator's procedures for synchronous generators as defined in Measurement III.C. S1, M1.	
Section 2 Measures	M2-1. The Generator Operator shall submit the documentation to be measured to the Regional Reliability Council on request (30 business days) to be reviewed to verify compliance with this Reliability Standard.	III.C.M2 Items to be measured	Information on the operation of synchronous generators in the non-automatic voltage control mode as defined in Measurement III.C. S1, M1.	
Section 2 Regional Differences	None identified		None identified	
Section 2 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Councils	III.C.M2 Timeframe  Compliance Monitoring Responsibility	On request (30 business days).  Regions	
Section 2 Levels of Non Compliance	Level 1 - Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 8 unit-hours, without permission from the Transmission Operator.  Level 2 - Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 16 unit-hours, without permission from the Transmission Operator.  Level 3 - Reports were incomplete, or indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 24 unit-hours, without permission from the Transmission Operator.  Level 4 - Reports on the requested information were not provided, or indicate incidents of synchronous generator	III.C.M2 Levels of Non-Compliance	Level 1 - Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 8 unit-hours, without permission from the Transmission Operator.  Level 2 - Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 16 unit-hours, without permission from the Transmission Operator.  Level 3 - Reports were incomplete, or indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 24 unit-hours, without permission from the Transmission Operator.  Level 4 - Reports on the requested information were not provided, or indicate incidents of synchronous generator	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	operation without automatic voltage control for a total of 24 unit-hours or more, without permission from the Transmission Operator.		operation without automatic voltage control for a total of 24 unit-hours or more, without permission from the Transmission Operator.	

Section 3	Generator operation for maintaining network voltage schedules.	III.C.M3 Brief Description	Generator operation for maintaining network voltage schedules.	
Section 3 Applicability	Transmission Operator	III.C.M3 Applicable to	III.C.M3 Transmission Operator/owner	
Section 3 Requirements	R3-1. Each Transmission Operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator, within the reactive capability of the unit, at a specified bus and shall provide this information to the Generator Operator. The Transmission Operator shall provide documentation of the information provided to the Generator Operator to the Regional Reliability Council and NERC on request (five business days).	III.C.M3 Standard	S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the Transmission Operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.	Added the phrase “within the reactive capability of the unit” from S2 to M3 to get R3-1
	R3-2. Each Transmission Operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The Transmission Operator shall make available the list of exempt generators to the Regional Reliability Council and NERC on request (five business days).	III.C.M3 Measurements	M3. Each Transmission Operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information provided to the generator owner/operator shall be provided to the Region and NERC on request (five business days).  Each Transmission Operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to the Region and NERC on	The Generator Operator should receive the voltage or reactive schedule rather than the Generator Owner as the Generation Operator is responsible for generator operation.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			request (five business days).	
Section 3 Measures	M3-1. The Transmission Operator has documentation of the voltage or reactive schedule provided to the Generator Operator.  M3-2. The Transmission Operator provides to the Regional Reliability Council and NERC upon request (five business days) the list of exempt generators.	III.C.M3 Items to be measured	Documentation of the voltage or reactive schedule provided to synchronous generator owners/operators.  List of exempt synchronous generators.	
Section 3 Regional Differences	None identified		None identified	
Section 3 Compliance Monitoring Process	On request (five business days).  Regional Reliability Council	III.C.M3 Timeframe Compliance Monitoring Responsibility	On request (five business days).  Regions	
Section 3 Levels of Non Compliance	Level 1 - Not applicable.  Level 2 - An incomplete list of exempt synchronous generators was provided  Level 3 - Incomplete documentation of the requested voltage or reactive schedule was provided.  Level 4 - No documentation of the voltage or reactive schedule was provided	III.C.M3 Levels of Non-Compliance	Level 1 - Not applicable.  Level 2 - An incomplete list of exempt synchronous generators was provided  Level 3 - Incomplete documentation of the requested voltage or reactive schedule was provided.  Level 4 - No documentation of the voltage or reactive schedule was provided	
Section 4	Generator operation for maintaining network voltage schedules.	III.C.M4 Brief Description	Generator operation for maintaining network voltage schedules.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 4 Applicability	Generator Operator	III.C.M4 Applicable to	Generation owners/operators	
Section 4 Requirements	<p>R4-1. Generator Operator shall maintain the synchronous generator voltage or reactive output as specified by the Transmission Operator, unless otherwise approved by the Transmission Operator.</p> <p>R4-2. When requested by the Regional Reliability Council and NERC, the Generator Operator shall provide (30 business days) a log that specifies the date, duration, and reason for not maintaining the established voltage or reactive power schedule, along with approvals for such operation received from the Transmission Operator.</p>	<p>III.C.M4 Standard</p> <p>III.C.M4 Measurements</p>	<p>S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the Transmission Operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.</p> <p>M4. Synchronous generator owners/operators shall maintain the voltage or reactive output as specified by the Transmission Operator, unless otherwise approved by the Transmission Operator.</p> <p>When requested by the Region and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date, duration, and reason for not maintaining the established voltage or reactive power schedule, along with approvals for such operation received from the Transmission Operator.</p>	Generator Operators are responsible for generator operation
Section 4 Measures	M4-1. Generator Operator has a log that specifies the date, duration, and reason for not maintaining the established voltage or reactive power schedule, along with approvals for such operation received from the Transmission Operator.	III.C.M4 Items to be measured	Log of date, duration, and reason for each specified period when the synchronous generator did not maintain the established network voltage or reactive power schedule, with documentation of any approvals for such operation received from the Transmission Operator.	
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring Process	<p>On request (30 business days).</p> <p>Regional Reliability Council</p>	<p>III.C.M4 Timeframe</p> <p>Compliance</p>	<p>On request (30 business days).</p> <p>Regions</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

		Monitoring Responsibility		
Section 4 Levels of Non Compliance	<p>Level 1 - Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 8 unit-hours, without permission from the Transmission Operator.</p> <p>Level 2 - Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 16 unit-hours, without permission from the Transmission Operator.</p> <p>Level 3 - Logs of synchronous generator operation off the voltage or reactive schedule were incomplete, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of less than 24 unit-hours, without permission from the Transmission Operator.</p> <p>Level 4 - Logs of synchronous generator operation off the voltage or reactive schedule were not provided, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of 24 unit-hours or more, without permission from the Transmission Operator.</p>	<p>III.C.M4</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 8 unit-hours, without permission from the Transmission Operator.</p> <p>Level 2 - Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 16 unit-hours, without permission from the Transmission Operator.</p> <p>Level 3 - Logs of synchronous generator operation off the voltage or reactive schedule were incomplete, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of less than 24 unit-hours, without permission from the Transmission Operator.</p> <p>Level 4 - Logs of synchronous generator operation off the voltage or reactive schedule were not provided, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of 24 unit-hours or more, without permission from the Transmission Operator.</p>	

Section 5	Tap settings of generator step-up and auxiliary transformers.	III.C.M5 Brief Description	Tap settings of generator step-up and auxiliary transformers.	
Section 5 Applicability	Transmission Operator	III.C.M5 Applicable to	Transmission System Operators	
Section 5	R5-1. The Transmission Operator shall have procedures	III.C.M5	S2. Synchronous generators shall maintain a network	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Requirements	<p>requiring the Generator Owner to provide tap settings, available tap ranges, and impedance data for generator step-up and auxiliary transformers. When tap changes are necessary, the Transmission Operator shall provide the Generator Owner and Generator Operator with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall also address generating unit exemption criteria (including any that may apply to nuclear units) and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements.</p> <p>R5-2. The Transmission Operator shall provide documentation of these procedures to the Regional Reliability Council and NERC on request (five business days).</p>	Standards and Measurements	<p>voltage or reactive power output as required by the Transmission Operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.</p> <p>M5. The Transmission Operator shall have procedures requiring synchronous generator owners/operators to provide tap settings, available tap ranges, and impedance data for generator step-up and auxiliary transformers. When tap changes are necessary, the Transmission Operator shall provide the generator owner/operator with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall also address generating unit exemption criteria (including any that may apply to nuclear units) and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements.</p> <p>Documentation of these procedures shall be provided to the Region and NERC on request (five business days).</p>	
Section 5 Measures	<p>M5-1. The Transmission Owner shall have procedures for reporting synchronous generator step-up and auxiliary transformer tap settings and available tap ranges as specified in Reliability Standard 065-R5-1.</p> <p>M5-2. The Transmission Owner shall have evidence it provided its procedures for reporting synchronous generator step-up and auxiliary transformer tap settings and available tap</p>	III.C.M5 Items to be measured	Procedures for reporting synchronous generator step-up and auxiliary transformer tap settings and available tap ranges.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	ranges to the Regional Reliability Council and NERC on request (five business days).			
Section 5 Regional Differences	None identified		None identified	
Section 5 Compliance Monitoring Process	On request (five business days).  Regional Reliability Council	III.C.M5 Timeframe Compliance Monitoring Responsibility	On request (five business days).  Regions	
Levels of Non Compliance	Level 1 - Procedures exist but do not include all the requirements as defined in above Requirement R1.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Procedures were not provided.	III.C.M5 Levels of Non-Compliance	Level 1 - Procedures exist but do not include all the requirements as defined in above Measurement M5.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Procedures were not provided.	
Section 6	Tap settings of generator step-up and auxiliary transformers.	III.C.M6  Brief Description	Tap settings of generator step-up and auxiliary transformers.	
Section 6 Applicability	Generator Owner	III.C.M6 Applicable to	Generation owners/operators	
Section 6	R6-1. The Generator Owner shall provide the tap settings and the available tap ranges and impedance data for	III.C.M6	S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the	The Generation Owner is responsible for maintenance,

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Requirements	<p>generator step-up and auxiliary transformers to the Transmission Operator, the Regional Reliability Council, and NERC on request (five business days) as defined in Requirement R5-1 of this Reliability Standard.</p> <p>R6-2. The Generator Owner shall change tap positions according to the procedures provided by the Transmission Operator within a mutually agreed upon time frame as defined in Requirement R5-1 of this Reliability Standard.</p>	Standards and Measurements	<p>Transmission Operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.</p> <p>M6. A synchronous generator owner/operator shall provide the tap settings and the available tap ranges and impedance data for generator step-up and auxiliary transformers to the Transmission Operator, the Region, and NERC on request (five business days). A generator owner/operator shall change tap positions according to the procedures provided by the Transmission Operator within a mutually agreed upon time frame as defined in Measurement III.C. S2, M5.</p>	including equipment data, and for providing voltage support to the Transmission Operator
Section 6 Measures	M6-1. The Generator Owner has documentation of tap settings and changes, available tap ranges, and impedances for generator step-up and auxiliary transformers.	III.C.M6 Items to be measured	Reporting of tap settings, available tap ranges, and impedances for generator step-up and auxiliary transformers.	
Section 6 Regional Differences	None identified		None identified	
Section 6 Compliance Monitoring Process	<p>On request (five business days).</p> <p>Regional Reliability Council</p>	<p>III.C.M6 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (five business days).</p> <p>Regions</p>	
Levels of Non Compliance	<p>Level 1 - Report does not include all the information requested as defined Requirement IIIC.S2.Section C.R1</p> <p>Level 2 - Not applicable.</p>	<p>III.C.M6 Levels of Non-Compliance</p>	<p>Level 1 - Report does not include all the information requested as defined in Measurement III.C. S2, M5.</p> <p>Level 2 - Not applicable.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 - Not applicable.</p> <p>Level 4 - Report on tap settings, available tap ranges, and impedances for generator step-up and auxiliary transformers was not provided, or report indicates generator operator did not change tap settings as requested by the Transmission Operator during the mutually agreed upon time frame.</p>		<p>Level 3 - Not applicable.</p> <p>Level 4 - Report on tap settings, available tap ranges, and impedances for generator step-up and auxiliary transformers was not provided, or report indicates generator owner/operator did not change tap settings as requested by the Transmission Operator during the mutually agreed upon time frame.</p>	
Section 7	Generators performance during temporary excursions in frequency, voltage, etc.	III.C.M7 Brief Description	Generators performance during temporary excursions in frequency, voltage, etc.	
Section 7 Applicability	Regional Reliability Council	III.C.M7 Applicable to	Regions	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 7 Requirements	<p>R7-1. The Regional Reliability Council shall establish requirements for generators to remain interconnected during temporary excursions in voltage, frequency, and real and reactive power output. These requirements shall include generator exemption criteria.</p> <p>R7-2. The Regional Reliability Council shall make available documentation of these excursion requirements to the Transmission Operator and NERC upon request (30 business days).</p>	III.C.M7 Standards and Measurements	<p>S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.</p> <p>M7. The Regions shall establish requirements for generators to remain interconnected during temporary excursions in voltage, frequency, and real and reactive power output. These requirements shall include generator exemption criteria.</p> <p>Documentation of these excursion requirements shall be available to the Transmission Operator and NERC upon request (30 business days).</p>	
Section 7 Measures	M7-1. The Regional Reliability Council shall provide to the Transmission Operator and NERC upon request (30 business days) documentation of the requirements for withstanding temporary excursions in voltage, frequency, and real and reactive power output of a generator.	III.C.M7 Items to be measured	Requirements for withstanding temporary excursions in voltage, frequency, and real and reactive power output of a generator.	
Section 7 Regional Differences	None identified		None identified	
Section 7 Compliance Monitoring Process	<p>On request (30 business days).</p> <p>NERC</p>	III.C.M7 Timeframe  Compliance Monitoring Responsibility	<p>On request (30 business days).</p> <p>NERC</p>	
Section 7 Levels of Non Compliance	Level 1 - Documentation of Regional Reliability Council requirements provided does not address all three generator parameters (voltage, frequency, or real and reactive power output).	III.C.M7 Levels of Non-Compliance	Level 1 - Documentation of Regional requirements provided does not address all three generator parameters (voltage, frequency, or real and reactive power output).	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Documentation of Regional Reliability Council requirements was not provided.</p>		<p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - Documentation of Regional requirements was not provided.</p>	

Section 8	Coordination of generator controls with the generator’s short-term capabilities and protective relays.	III.C.M8 Brief Description	Coordination of generator controls with the generator’s short-term capabilities and protective relays.	
Section 8 Applicability	Generator Owner	III.C.M8 Applicable to	III.C.M8 Generator owner/operator	Generation Owner is responsible for this
Section 8 Requirements	R8-1. The Generator Owner shall provide the Regional Reliability Council, the Transmission Operator, and NERC, as requested (30 business days), with information that ensures that the generator voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) coordinate with the generator’s short-term capabilities and protective relays, unless exempted by the Regional Reliability Councils.	III.C.M8 Standard  Measurements	<p>S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator’s short duration capabilities and protective relays.</p> <p>M8. Generator owners/operators shall provide the Region, the Transmission Operator, and NERC, as requested (30 business days), with information that ensures that the generator voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) coordinate with the generator’s short-term capabilities and protective relays, unless exempted by the Region.</p>	
Section 8	M8-1. The Generator Owner shall have information indicating	III.C.M8	Information indicating coordination of generator voltage	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Measures	coordination of generator voltage regulator controls and limit functions with the generator’s short-term capabilities and protective relays.	Items to be measured	regulator controls and limit functions with the generator’s short-term capabilities and protective relays.	
Section 8 Regional Differences	None identified		None identified	
Section 8 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Council	III.C.M8 Timeframe  Compliance Monitoring Responsibility	On request (30 business days).  Regions	
Section 8 Levels of Non Compliance	Level 1 - Information on generator voltage regulator controls and limit functions and their coordination with the generator’s short-term capabilities and protective relays was provided, but was incomplete in one or more areas.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Information on generator controls and their coordination with the generator’s short-term capabilities and protective relays was not provided.	III.C.M8 Levels of Non-Compliance	Level 1 - Information on generator voltage regulator controls and limit functions and their coordination with the generator’s short-term capabilities and protective relays was provided, but was incomplete in one or more areas.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Information on generator controls and their coordination with the generator’s short-term capabilities and protective relays was not provided.	
Section 9	Speed/load governing system.	III.C.M9 Brief Description	Speed/load governing system.	
Section 9 Applicability	Generator Owners	III.C.M9 Applicable to	Generator owner/operator	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 9 Requirements	<p>R9-1. The Generator Owner shall:</p> <ul style="list-style-type: none"> <li>(a) Provide the Regional Reliability Council, the Transmission Operator, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system.</li> <li>(b) Coordinate boiler or nuclear reactor control to maintain the capability of the generator to aid control of system frequency during an electric system disturbance.</li> <li>(c ) Report non-functioning or blocked speed/load governor controls to the Regional Reliability Council, the Transmission Operator, and NERC on request (30 business days).</li> </ul>	<p>III.C.M9 Standard</p> <p>Measurement</p>	<p>S5. Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.</p> <p>M9. Generator owners/operators shall provide the Region, the Transmission Operator, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Non-functioning or blocked speed/load governor controls shall be reported to the Region, the Transmission Operator, and NERC on request (30 business days).</p>	
Section 9 Measures	<p>M9-1. The Generator Owner shall have documentation:</p> <ul style="list-style-type: none"> <li>(a) Of the characteristics of the generator's speed/load governing system</li> <li>(b) That confirms the coordinate boiler or nuclear reactor control to maintain the capability of the generator to aid control of system frequency during an electric system disturbance.</li> <li>(c) Of non-functioning or blocked speed/load governor controls.</li> </ul> <p>M9-2. The Generator Owner shall have evidence it reported non-functioning or blocked speed/load governor controls to the Regional Reliability Council, the Transmission Operator, and NERC on request (30 business days).</p>	<p>III.C.M9 Items to be measured</p>	<p>Documentation of the characteristics of the generator's speed/load governing system and notification of blocked speed/load governor controls.</p> <p>.</p>	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 9 Regional Differences	None identified		None identified	
Section 9 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Council	III.C.M9  Timeframe  Compliance Monitoring Responsibility	On request (30 business days).  Regions	
Section 9 Levels of Non Compliance	Level 1 - Information on the generator's speed/load governing system was provided but did not include all the requirements as defined above in Requirement R1.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Information on the generator's speed/load governing system was not provided.	III.C.M9 Levels of Non-Compliance	Level 1 - Information on the generator's speed/load governing system was provided but did not include all the requirements as defined above in Measurement M9.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Information on the generator's speed/load governing system was not provided.	

Section 10	Regional procedure on generator protection operations	III.C.M10 Brief Description	Regional procedure on generator protection operation	
Section 10 Applicability	Regional Reliability Council	III.C.M10 Applicable to	III.C.M10 Regions	
Section 10	R10-1. Each Regional Reliability Council shall have in place a procedure for the monitoring, review, analysis, and	III.C.M10 Standard	S6. All generation protection system misoperations shall	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Requirements	<p>correction of generation protection system operations.</p> <p>The procedure shall require that misoperations be analyzed for cause and that corrective actions be implemented. The procedure shall also require that a record of such analysis and corrective actions be maintained and be provided to the Regional Reliability Council and NERC on request (five business days).</p> <p>The procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring, analysis, and notification of all generation protective device misoperations.</li> <li>2. List of the data reporting requirements (periodically and format).</li> <li>3. Requirements for analysis and documentation of corrective action plans for misoperations.</li> <li>4. Periodicity of review of the procedure by the Regional Reliability Council.</li> <li>5. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.</li> <li>6. Regional definition of misoperation.</li> </ol> <p>R10-2 The Regional Reliability Council shall provide documentation of the procedure for the monitoring, review, analysis, and correction of generation protection system operations to NERC on request (five business</p>	III.C.M10 Measurements	<p>be analyzed for cause and corrective action.</p> <p>M10. Each Region shall have in place a procedure for the monitoring, review, analysis, and correction of generation protection system operations.</p> <p>The procedure shall require that misoperations be analyzed for cause and that corrective actions be implemented. (Each Region shall define misoperations.) The procedure shall also require that a record of such analysis and corrective actions be maintained and be provided to the Region and NERC on request (five business days).</p> <p>The Regional procedure shall include the following elements:</p> <ol style="list-style-type: none"> <li>1. Requirements for monitoring, analysis, and notification of all generation protective device misoperations.</li> <li>2. List of the data reporting requirements (periodically and format).</li> <li>3. Requirements for analysis and documentation of corrective action plans for misoperations.</li> <li>4. Periodicity of review of the procedure by the Region.</li> <li>5. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.</li> </ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	days).		6. Regional definition of misoperation.	
Section 10 Measures	<p>M10-1. The Regional Reliability Council has documentation of the procedure for monitoring, review, analysis, and correction of all generator protection operations.</p> <p>M10-2. The Regional Reliability Council shall have evidence it provided documentation of its procedure for monitoring, review, analysis, and correction of generation protection system operations to NERC as requested (five business days).</p>	III.C.M10 Items to be measured	<p>Procedure for monitoring, review, analysis, and correction of all generator protection operations.</p> <p>.</p>	
Section 10 Regional Differences	None identified		None identified	
Section 10 Compliance Monitoring Process	<p>On request (five business days).</p> <p>NERC</p>	<p>III.C.M10</p> <p>Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (five business days).</p> <p>NERC</p>	
Section 10 Levels of Non Compliance	<p>Level 1 - The Regional procedure does not address all the requirements as defined above in Requirement R1.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - The Regional procedure was not provided.</p>	<p>III.C.M10</p> <p>Levels of Non-Compliance</p>	<p>Level 1 - The Regional procedure does not address all the requirements as defined above in Measurement M10.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - The Regional procedure was not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 11	Analysis of misoperations of generator protection equipment	III.C.M11 Brief Description	Analysis of misoperations of generator protection equipment	
Applicability	Generator Owners	III.C.M11 Applicable to	Generation owner/operator	
Requirements	<p>R11-1. The Generator Operator shall:</p> <p>(a) Analyze protection system operations and report and maintain a record of all misoperations in accordance with the Regional Reliability Council procedures in Requirement III.C.S6.Section A.R1.</p> <p>(b) Take corrective actions to avoid future misoperations.</p> <p>R11-2. The Generator Operator shall provide documentation of the analysis and corrective actions to the Regional Reliability Council and NERC on request (30 business days).</p>	<p>III.C.M11 Standard</p> <p>III.C.M11 Measurements</p>	<p>S6. All generation protection system misoperations shall be analyzed for cause and corrective action.</p> <p>M11. Generator owners/operators shall analyze protection system operations and report and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.C. S6, M10. Corrective actions shall be taken to avoid future misoperations.</p> <p>Documentation of the analysis and corrective actions shall be provided to the affected Regions and NERC on request (30 business days).</p>	Comment: “affected” was removed. The original idea was that more than one Region could be affected by a misoperation. Perhaps this should be covered under disturbance reporting
Section 11 Measures	<p>M11-1 The Generator Operator’s documentation of generator protection misoperations, analyses, and corrective actions includes all items specified in Reliability Standard 069-R11-1.</p> <p>M11-2. The Generator Operator shall have evidence it provided the Regional Reliability Council and NERC with documentation of the protective misoperations, analyses and corrective actions as specified in Reliability Standard 069-R11-2.</p>	III.C.M11  Items to be measured	Documentation of protection misoperations, analyses, and corrective actions.	
Section 11 Regional	None identified		None identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Differences				
Section 11 Compliance Monitoring Process	<p>On request (30 business days).</p> <p>Regional Reliability Council</p>	<p>III.C.M11 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (30 business days).</p> <p>Regions</p>	
Section 11 Levels of Non Compliance	<p>Level 1 - Documentation of generator protection system misoperations was provided but does not address all identified misoperations or does not provide a record of corrective actions taken for all identified misoperations.</p> <p>Level 2 - Documentation of generator protection system misoperations was provided but was lacking one of these three elements: (a) a complete record of misoperations for the time and place requested, (b) an analysis of all misoperations, and (c) a record of corrective actions taken.</p> <p>Level 3 - Documentation was provided but was lacking two of these three elements: (a) a complete record of misoperations for the time and place requested; (b) an analysis of all misoperations; (c) a record of corrective actions taken.</p> <p>Level 4 - No documentation of generator protection system misoperations was provided</p>	<p>III.C.M11 Levels of Non- Compliance</p>	<p>Level 1 - Documentation of generator protection system misoperations was provided but does not address all identified misoperations or does not provide a record of corrective actions taken for all identified misoperations.</p> <p>Level 2 - Documentation of generator protection system misoperations was provided but was lacking one of these three elements: (a) a complete record of misoperations for the time and place requested, (b) an analysis of all misoperations, and (c) a record of corrective actions taken.</p> <p>Level 3 - Documentation was provided but was lacking two of these three elements: (a) a complete record of misoperations for the time and place requested; (b) an analysis of all misoperations; (c) a record of corrective actions taken.</p> <p>Level 4 - No documentation of generator protection system misoperations was provided</p>	
Section 12	Maintenance and testing of generator protection systems	III.C.M12 Brief Description	Maintenance and testing of generator protection systems	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 12 Applicability	Generator Operator	III.C.M12 Applicable to	III.C.M12 Generator owner/operator.	
Section 12 Requirements	<p>R12-1. Generator Operators shall have a generator protection system maintenance and testing program in place. This program shall include protection system identification, frequency of protection system testing, and frequency of protection system maintenance.</p> <p>R12-2. Documentation of the program and its implementation shall be provided to the appropriate Regional Reliability Council and NERC on request (30 business days).</p>	III.C.M12  Standards and Measurements	<p>S7. Generation protection system maintenance and testing programs shall be developed and implemented.</p> <p>M12. Generator owners/operators shall have a generator protection system maintenance and testing program in place. This program shall include protection system identification, frequency of protection system testing, and frequency of protection system maintenance.</p> <p>Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (30 business days).</p>	
Section 12 Measures	<p>M12-1. The Generator Operator 's generator protection system maintenance and testing program and its implementation includes all items specified in Reliability Standard 065-R12-1.</p> <p>M12-2. The Generator Operator shall have evidence it provided documentation of its generator protection system maintenance and testing program and its implementation to as specified in Reliability Standard 065-R12-2.</p>	III.C.M12  Items to be measured	<p>Documentation and implementation of generator protection system maintenance and testing program.</p> <p>.</p>	
Section 12 Regional Differences	None identified		None identified	
Section 12 Compliance Monitoring	On request (30 business days).	III.C.M12 Timeframe	On request (30 business days).	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Process	Regional Reliability Council	Compliance Monitoring Responsibility	Regions	
Section 12 Levels of Non Compliance	<p>Level 1 - Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.</p> <p>Level 2 - Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.</p> <p>Level 3 - Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.</p> <p>Level 4 - No documentation of the maintenance and testing program or its implementation was provided.</p>	III.C.M12 Levels of Non-Compliance	<p>Level 1 - Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.</p> <p>Level 2 - Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule..</p> <p>Level 3 - Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.</p> <p>Level 4 - No documentation of the maintenance and testing program or its implementation was provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
ID Number	066	Compliance Templates III.B.M1 III.B.M2 III.B.M3	III. System Protection and Control  B. Transmission Control Devices  Measurements 1, 2 and 3	
Title	Transmission System Control Devices	Sections	III. System Protection and Control  B. Transmission Control Devices	Use appropriate portions of Section
Purpose	To ensure that transmission control devices reliably coordinated with other control devices within a Region and, where appropriate, with neighboring Regions, they need be planned and designed to meet the system performance requirements as defined in Reliability Standard 051.	Standard for III.B	S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.	Standard S1 was modified to reference the appropriate Version 0 standard
Effective Date	February 8, 2005	Approval Dates	I.B.M1, I.B.M2 and I.B.M3, proposed for Phase 4, NERC Engineering Committee approved July 14, 1998	
Standard Applicability	Transmission owners. (for Section 1, 2 and 3)	Applicability	Transmission Owners for I.B.M1 and I.B.M2 Transmission Owners or Operators for I.B.M3	
Section 1	Assessment of transmission control devices.	Brief Descriptions III.B.M1	Assessment of transmission control devices.	
Section 1 Applicability	Planning Authority and Transmission Planner.	III.B.M1 Applicable to	Transmission Owners	Incorporated Functional Model terminology





Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 1 Measures	M1-1. Evidence that the Transmission Owner has assessed and provided such assessments of its transmission control devices in accordance with the requirements Reliability Standard 066-R1-1 and R1-2.	IIIBM1 Items to be Measured	Assessment of the reliability impact of transmission control devices.	Included with “Items to be measured” the requirement to provide the information on request
Section 1 Regional Differences	None identified	None	None identified	
Section 1 Compliance Monitoring Process	Each Regional Reliability Council shall monitor compliance.	IIIBM1 Compliance - Monitoring Responsibility  Timeframe --	Regions.  On request (within 30 days).	
Section 1 Levels of Non Compliance	<p>Level 1 - Assessments of the reliability impact of transmission control devices were provided per R1-2, but were incomplete per R1-1.</p> <p>Level 2 - Assessments of the reliability impact of transmission control devices were not provided per R1-2, but were complete per R1-1 when submitted.</p> <p>Level 3 - Assessments of the reliability impact of transmission control devices were not provided per R1-2, and were incomplete per R1-1 when submitted.</p> <p>Level 4 - Assessments of the reliability impact of transmission control devices were not provided.</p>	IIIBM1  Levels of non-compliance	<p>Level 1 - Assessments of the reliability impact of transmission control devices were provided on schedule, but were incomplete in one or more areas.</p> <p>Level 2 - Assessments of the reliability impact of transmission control devices were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Assessments of the reliability impact of transmission control devices were not provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Assessments of the reliability impact of transmission control devices were not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 2	Provision of models and data for control devices for use in system modeling.	Brief Descriptions III.B.M2	Provision of models and data for control devices for use in system modeling.	
Section 2 Applicability	Transmission owners	III.B.M2 Applicable to	Transmission owners	Incorporated Functional Model terminology
Section 2 Requirements	<p>R2-1. Transmission owners shall provide transmission control device models and data suitable for use in system modeling.</p> <p>Transmission owners shall provide preliminary models and data for transmission control devices to permit analysis of the potential impacts of these devices on system reliability prior to their installation.</p> <p>Validated models and data, based on commissioning test results, shall be provided after the in-service dates of the control devices so that the impacts of these devices on system security may be fully assessed and incorporated into operating security limits.</p> <p>R2-2. Validated transmission control device models and data</p>	<p>Standard for III.B.M2</p> <p>III.B.M2 Measurement</p> <p>III.B.M2 Full (100%) Compliance Requirements</p>	<p>S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.</p> <p>M2. Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization.</p> <p>Full (100%) Compliance Requirements</p> <p>Transmission owners shall provide transmission control device models and data suitable for use in system modeling. These models and data will be used in the assessments of the reliability of the transmission network under Standard I.A. Transmission owners shall provide</p>	<p>The content of S1 is repeated and detailed more completely in the M2 measurement and therefore not used directly in translation.</p> <p>The content of M2 is repeated and detailed more completely in the Full (100%) Compliance Requirements and therefore not used directly in translation.</p> <p>Full (100%) Compliance Requirements were used for R2-1 except for the last sentence regarding “requests”</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	should be provided to the Regions and NERC on request (within 30 days).		<p>preliminary models and data for transmission control devices to permit analysis of the potential impacts of these devices on system reliability prior to their installation. Validated models and data, based on commissioning test results, shall be provided after the in-service dates of the control devices so that the impacts of these devices on system security may be fully assessed and incorporated into operating security limits.</p> <p>Validated transmission control device models and data should be provided to the Regions and NERC on request (within 30 days).</p>	which was used for R2-2.
Section 2 Measures	M2-1. Evidence that the Transmission Owner has provided transmission control device models and data in accordance with the requirements R2-1 and R2-2.	III.B.M2 Items to be Measured	Transmission control device models and data.	Included with “Items to be measured” the requirement to provide the information on request
Section 2 Regional Differences	None identified	None	None identified	
Section 2 Compliance Monitoring Process	<p>On request (within 30 days).</p> <p>Each Regional Reliability Council</p>	<p>III.B.M2 Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>On request (within 30 days).</p> <p>Regions</p>	
Section 2 Levels of Non Compliance	<p>Level 1 - Control device models and data for use in system modeling were provided per R2-2, but were incomplete per R2-1.</p> <p>Level 2 - Control device models and data for use in system</p>	<p>III.B.M2</p> <p>Levels of Non-</p>	Level 1 - Control device models and data for use in system modeling were provided on schedule, but were incomplete in one or more areas.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>modeling were not provided per R2-2, but were complete per R2-1 when submitted.</p> <p>Level 3 - Control device models and data for use in system modeling were not provided per R2-2, and were incomplete per R2-1 when submitted.</p> <p>Level 4 - Control device models and data for use in system modeling were not provided.</p>	Compliance	<p>Level 2 - Control device models and data for use in system modeling were not provided on schedule, but were complete when submitted.</p> <p>Level 3 - Control device models and data for use in system modeling were not provided on schedule, and were incomplete in one or more areas when submitted.</p> <p>Level 4 - Control device models and data for use in system modeling were not provided.</p>	
Section 3	Periodic review of settings and operating strategies of control devices.	Brief Descriptions III.B.M3	Periodic review of settings and operating strategies of control devices.	
Section 3 Applicability	Transmission Owners	III.B.M3 Applicable to	Transmission Owners or Operators	Indicate primary responsibility
Section 3 Requirements	<p>R3-1. The Transmission Owner and Transmission Operator shall review the settings and operating strategies of transmission control devices whenever changes to the system are made or at least every five years to ensure that these control devices continue to perform their intended function.</p> <p>R3-2. The Transmission Owner and Transmission Operator shall</p>	<p>Standard for III.B.M3</p> <p>III.B.M3 Measurement</p>	<p>S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.</p> <p>M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the</p>	<p>The content of S1 is repeated and detailed more completely in the M3 measurement and therefore not used directly in translation.</p> <p>The content of M3 is repeated and detailed more completely in the Full (100%) Compliance Requirements and therefore not used</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	provide documentation of its current settings and operating strategies to the Regions and NERC on request (within 30 days)	III.B.M3  Full (100%) Compliance Requirements	Regions and NERC on request.  Full (100%) Compliance Requirements  Transmission owners or operators shall review the settings and operating strategies of transmission control devices whenever changes to the system are made or at least every five years to ensure that these control devices continue to perform their intended function. Documentation of the current settings and operating strategies shall be provided to the Regions and NERC on request (within 30 days).	directly in translation.   Full (100%) Compliance Requirements were used for R3-1 except for the last sentence regarding “documentation” which was used for R3-2.
Section 3 Measures	M3-1. The Transmission Owner shall have evidence that it reviewed the settings and operating strategies of transmission control devices in accordance with Reliability Standard 066- R3-1 and R3-2.	III.B.M3 Items to be Measured	Periodic review and validation of settings and operating strategies.	Included with “Items to be measured” the requirement to provide the information on request
Section 3 Regional Differences	None identified	None	None identified	
Section 3 Compliance Monitoring Process	When conditions change or at least every five years.  Each Regional Reliability Council	III.B.M3 Timeframe  Compliance Monitoring Responsibility	When conditions change or at least every five years.  Regions.	
Section 3 Levels of Non Compliance	Level 1 - A review of control device settings and operating strategies was provided per R3-2, but was incomplete per R3-1.  Level 2 - A review of control device settings and operating strategies was not provided per R3-2, but was complete per R3-1 when submitted.	III.B.M3  Levels of Non-Compliance	Level 1 - A review of control device settings and operating strategies was provided on schedule, but was incomplete in one or more areas.  Level 2 - A review of control device settings and operating strategies was not provided on schedule, but was complete	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 - A review of control device settings and operating strategies was not provided per R3-2, and was incomplete per R3-1 when submitted.</p> <p>Level 4 - A review of control device settings and operating strategies was not provided.</p>		<p>when submitted.</p> <p>Level 3 - A review of control device settings and operating strategies was not provided on schedule, and was incomplete in one or more areas when submitted.</p> <p>Level 4 - A review of control device settings and operating strategies was not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	067	Compliance Template III.D.M1 III.D.M2 III.D.M3 III.D.M4	III. System Protection and Control  D. Under Frequency Load Shedding	
Title	Under Frequency Load Shedding (underfrequency load shedding)	Sections	III. System Protection and Control  D. Under Frequency Load Shedding	
Purpose	Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (underfrequency load shedding) Program requiring end users of electricity on the bulk electric system to drop loads to arrest declining system frequency during capacity shortages resulting from system islanding or other major system disturbances.			
Effective Date	February 8, 2005	Approval Dates	III.D.M1 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 III.D.M2 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 III.D.M3 - CTTF Revised Compliance Template, BOT Approved April 2, 2004 III.D.M4 - Approved by NERC Board of Trustees on October 16, 2001	
Standard Applicability	Section 1 - Regional Reliability Council  Section 2 - Transmission Operator, Transmission Owner, Load-serving Entity, Distribution Provider, as required by the Regional Reliability Council to have an underfrequency load shedding	Applicability	M1 - Regional Reliability Councils  M2 – Entities owning, operating, or required (by the Regions) to have an UFLS program.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>program</p> <p>Section 3 - Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider, required by the Regional Reliability Council to have an underfrequency load shedding program</p> <p>Section 4 - Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider, required by the Regional Reliability Council to have an underfrequency load shedding program</p>		<p>M3 – Entities owning, operating, or required (by the Regions) to have an UFLS program.</p> <p>M4 - Entities owning, operating, or required (by the Regions) to have an UFLS program.</p>	
Section 1	Development and documentation of Regional Reliability Councils’ underfrequency load shedding (underfrequency load shedding) programs	III.D.M1 Brief Description	Development and documentation of Regional underfrequency load shedding (UFLS) programs coordinated within and among Regions.	
Section 1 Applicability	Regional Reliability Council	III.D.M1 Applicable to	Regional Reliability Councils	
Section 1 Requirements	R1-1. Each Regional Reliability Council shall develop,	III.D.M1 Standard  III.D.M1	S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>coordinate, and document an underfrequency load shedding Program, which shall include the following:</p> <ol style="list-style-type: none"> <li>1. Requirements for coordination of underfrequency load shedding programs within the subregions, Regional Reliability Council, and, where appropriate, among Regional Reliability Councils.</li> <li>2. Design details shall include, but are not limited to: <ol style="list-style-type: none"> <li>a. Frequency set points</li> <li>b. Size of corresponding load shedding blocks (% of connected loads)</li> <li>c. intentional and total tripping time delays</li> <li>d. generation protection</li> <li>e. tie tripping schemes</li> <li>f. islanding schemes</li> <li>g. automatic load restoration schemes</li> <li>h. any other schemes that are part of or impact the underfrequency load shedding programs</li> </ol> </li> <li>3. A Regional Reliability Council underfrequency load shedding program database. This database shall be updated as specified in the Regional Reliability Council Program (but at least every five years) and shall include sufficient information to model the underfrequency load shedding program in dynamic simulations of the interconnected transmission systems.</li> </ol>	Measure	<p>M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:</p> <ol style="list-style-type: none"> <li>1. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.</li> <li>2. Design details shall include, but are not limited to: <ol style="list-style-type: none"> <li>a. size of coordinated load shedding blocks (% of connected load)</li> <li>b. corresponding frequency set points</li> <li>c. intentional and total tripping time delays</li> <li>d. related generation protection</li> <li>e. tie tripping schemes</li> <li>f. islanding schemes</li> <li>g. automatic load restoration schemes</li> <li>h. any other schemes that are part of or impact the UFLS programs</li> </ol> </li> <li>3.) A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.</li> <li>4.) Technical assessment and documentation of</li> </ol>	<p>Design details 2 a and b are interchanged in the new draft since most regions use them in the order listed in the draft.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>4. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional underfrequency load shedding program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:</p> <p class="list-item-l1">a. A review of the frequency set points and timing, and</p> <p class="list-item-l1">b. Dynamic simulation of possible disturbance that cause the region or portions of the region to experience the largest imbalance between demand (load) and generation.</p> <p>R1-2. The Regional Reliability Council shall provide documentation of its underfrequency load shedding program and its database information to NERC on request (within 30 days).</p> <p>R1-3. The Regional Reliability Council shall provide documentation of the technical assessment of its underfrequency load shedding program to NERC on request (within 30 days).</p>		<p>the effectiveness of the design and implementation of the Regional UFLS program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:</p> <p class="list-item-l1">a. A review of the frequency set points and timing, and</p> <p class="list-item-l1">b. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.</p> <p>Documentation of each Region’s UFLS program and its database information shall be provided to NERC on request (within 30 days). Documentation of the technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days).</p>	
Section 1 Measures	<p>M1-1 The Regional Reliability Council shall have documentation of the underfrequency load shedding Program and Current underfrequency load shedding database.</p> <p>M1-2 The Regional Reliability Council shall have evidence it provided documentation of its its underfrequency load shedding program and its database information to NERC as specified in Reliability Standard 067-R1-2.</p>	III.D.M1 Items to be Measured	The documentation and coordination of Regional UFLS programs.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	M1-3 The Regional Reliability Council shall have evidence it provided documentation of its technical assessment of its underfrequency load shedding program to NERC as specified in Reliability Standard 067-R1-3.			
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	On request (within 30 days) for the program, database, and results of technical assessments.  NERC	III.D.M1 Timeframe  III.D.M1 Compliance Monitoring Responsibility	On request (within 30 days) for the program, database, and results of technical assessments.  NERC	
Section 1 Levels of Non Compliance	Level 1 — Documentation demonstrating the coordination of the Regional Reliability Council’s underfrequency load shedding program was incomplete in one of the elements in Reliability Standard 067-R1-1..  Level 2 — N/A  Level 3 — N/A  Level 4 — Documentation demonstrating the coordination of the Regional Reliability Council’s underfrequency load shedding program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional Reliability Council’s underfrequency load shedding program was not provided, or an assessment was not completed in the	III.D.M1  Levels of Non-compliance	Level 1 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in one of the requirements in Measure M1.  Level 2 — N/A  Level 3 — N/A  Level 4 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional UFLS program was not provided, or an assessment was not completed in the last five years.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	last five years.			
Section 2	Assuring Consistency of entity underfrequency load shedding programs with Regional Reliability Council’s underfrequency load shedding Program requirements.	III.D.M2 Brief Description	Assuring consistency of entity UFLS programs with Regional UFLS requirements.	
Section 2 Applicability	Transmission Operator, Transmission Owner, Load-serving Entity, Distribution Provider,as required by the Regional Reliability Council to have an underfrequency load shedding program	III.D.M2 Applicability	Entities owning, operating, or required (by the Regions) to have an UFLS program.	
Section 2 Requirements	R2-1. The Transmission Owner, Transmission Operator, Load-serving Entity, and Distribution Provider, that owns or operates an underfrequency load shedding program as required by the Regional Reliability Council shall ensure that their program is consistent with the Regional Reliability Council’s underfrequency load shedding Program requirements. Such entities shall provide and annually update their underfrequency load shedding data as necessary for the RRC to maintain and update an	III.D.M2 Standard  III.D.M2 Measurement	S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.  M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measure III.D.M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update an UFLS program as specified in Measure III.D.M1.	Removed ‘As specified in Measure III D M1’ since that requirement specifies what the Program shall include, not the Program itself.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>underfrequency load shedding program database.</p> <p>R2-2 The Transmission Owner, Transmission Operator, Load-serving Entity, and Distribution Provider, that owns or operates an underfrequency load shedding program as required by the Regional Reliability Council shall provide its documentation of that program to the Regional Reliability Council on request (30 days).</p>		<p>The documentation of an entity’s UFLS program shall be provided to the Region on request (within 30 days).</p>	
Section 2 Measures		III.D.M2 Items to be Measured	Consistency of entity’s UFLS program with Regional UFLS requirements.	
Section 2 Regional Differences	None identified		None identified	
Section 2 Compliance Monitoring Process	<p>On request (within 30 days).</p> <p>Regional Reliability Council</p>	<p>III.D.M2 Timeframe</p> <p>III.D.M2 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days).</p> <p>Regions.</p>	
Section 2 Levels of Non Compliance	Level 1 — Evaluations of entity underfrequency load shedding programs for consistency with the Regional Reliability Council’s underfrequency load shedding Program were incomplete/inconsistent in one or more	III.D.M2 Levels of Non-	Level 1 — Evaluations of entity UFLS programs for consistency with the Regional UFLS program were incomplete/inconsistent in one or more requirements of Measure III.D.M1 but is consistent	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>requirements of Reliability Standard 067-R1, but is consistent with the required load shed.</p> <p>Level 2 — The amount of load shedding is less than 95% of the regional requirements in any of the load steps.</p> <p>Level 3 — The amount of load shedding is less than 90% of the regional requirements in any of the load steps.</p> <p>Level 4 — The amount of load shedding is less than 85% of the regional requirements on any of the load steps, or evaluations of entity underfrequency load shedding programs for consistency with the Regional Reliability Council’s underfrequency load shedding program were not provided.</p>	compliance	<p>with the required load shed.</p> <p>Level 2 — The amount of load shedding is less than 95% of the regional requirements in any of the load steps.</p> <p>Level 3 — The amount of load shedding is less than 90% of the regional requirements in any of the load steps.</p> <p>Level 4 — The amount of load shedding is less than 85% of the regional requirements on any of the load steps, or evaluations of entity UFLS programs for consistency with the Regional UFLS program were not provided.</p>	
Section 3	Implementation and documentation of underfrequency load shedding equipment maintenance program.	III.D.M3 Brief Description	Implementation and documentation of UFLS equipment maintenance program.	
Section 3 Applicability	Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider, required by the Regional Reliability Council to have an underfrequency load shedding program	III.D.M3 Applicability	Entities owning, operating, or required (by the Regions) to have an UFLS program.	
Section 3 Requirements	R3-1. The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program shall have an underfrequency load shedding equipment maintenance and testing program in place. This program shall include underfrequency load shedding equipment identification, the schedule for	III.D.M3 Standard	S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>underfrequency load shedding equipment testing, and the schedule for underfrequency load shedding equipment maintenance.</p> <p>R3-2 The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program shall provide the results of implementation to the Regional Reliability Council(s) and NERC on request (within 30 days).</p>	III.D.M3 Measurement	<p>restoration programs, and transmission protection and control systems.</p> <p>M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.</p> <p>These programs shall be maintained and documented, and the results of implementation shall be provided to the Regions and NERC on request (within 30 days).</p>	
Section 3 Measure	<p>M3-1 The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program shall have an underfrequency load shedding equipment maintenance and testing program in place that contains the elements specified in Reliability Standard 067-R3-1.</p> <p>M3-2 The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program shall have evidence it provided the results of the program's implementation to the Regional Reliability Council(s) and NERC on request (within 30 days).</p>	III.D.M3 Items to be Measured	Each entity's UFLS equipment maintenance program.	
Section 3 Regional Differences	None identified		None identified	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Compliance Monitoring Process	On request (within 30 days).  Regional Reliability Council	III.D.M3 Timeframe  III.D.M3 Compliance Monitoring Responsibility	On request (within 30 days).  Regions.	
Section 3 Levels of Non Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation was not provided.	III.D.M3 Levels of Non Compliance	Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation was not provided.	
Section 4	Analysis and Documentation of underfrequency load shedding performance following an underfrequency event	III.D.M4 Brief Description	Analysis and Documentation of UFLS program performance	Added “following an underfrequency event” for clarification.
Section 4 Applicability	Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider, required by the Regional Reliability Council to have an underfrequency load shedding	III.D.M4 Applicability	Entities owning, operating, or required (by the Regions) to have an UFLS program.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	program shall provide documentation of the analysis of its underfrequency load shedding program to the Regional Reliability Council(s) and NERC on request 90 days after the system event.		Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.	
Section 4 Measures	<p>M4-1 The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program’s analysis and documentation of underfrequency load shedding program performance following an underfrequency event shall include all elements identified in Reliability Standard 067-R4-1.</p> <p>M4-2 The Transmission Owner, Transmission Operator, Load-serving Entity , Distribution Provider required by the Regional Reliability Council to have an underfrequency load shedding program shall have evidence it provided documentation of the analysis of its underfrequency load shedding program performance following an underfrequency event as specified in Reliability Standard 067-R4-1.</p>	III.D.M4 Items to be Measured	Analysis of UFLS program performance for underfrequency events below the UFLS set points.	
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring Process	On request 90 days after the system event. Regional Reliability Council	III.D.M4 Timeframe III.D.M4 Compliance Monitoring Responsibility	On request 90 days after the system event. Regions.	
Section 4 Levels of Non	Level 1 - Analysis of underfrequency load shedding program performance following an actual underfrequency event below the	III.D.M4	Level 1 - Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s)	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Compliance	<p>underfrequency load shedding set point(s) was incomplete in one or more elements in Reliability Standard 067-R4-1.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable</p> <p>Level 4 - Analysis of underfrequency load shedding program performance following an actual underfrequency event below the underfrequency load shedding set point(s) was not provided.</p>	Levels of Non Compliance	<p>was incomplete in one or more requirements of Measurement M4.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable</p> <p>Level 4 - Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	068	Compliance Templates III.E.M1 III.E.M2 III.E.M3 III.E.M4 III.E.M5	III. System Protection and Control  E. Under Voltage Load Shedding	
Title	Undervoltage Load Shedding	Sections	III. System Protection and Control  E. Under Voltage Load Shedding	
Purpose	Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding program requiring end users of electricity on the bulk electric system to drop loads.			
Effective Date	February 8, 2005	Approval - Dates	III.E.M1 – October 9, 2004 III.E.M2 – October 9, 2004 III.E.M3 – April, 2004 III.E.M4 - April, 2004 III.E.M5 – October 9. 2004	
Standard Applicability	Section 1 – Load-serving Entity, Transmission Owner and Distribution Provider  Section 2 – Regional Reliability Council  Section 3 – Load-serving Entity, Transmission Owner, Transmission Operator and Distribution Provider that owns an under voltage load shedding system  Section 4 – Load serving entity, Transmission Owner, Transmission Operator and Distribution provider that owns an under voltage load shedding system	Applicability	M1 – UVLS owners and operators.  M2 – Regions  M3 – UVLS owners and operators.  M4 – UVLS owners and operators  M5 - UVLS owners and operators.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Section 5 - Load-serving Entity, Transmission Owner, Transmission Operator, Distribution Provider that owns or operates an undervoltage load shedding program			
Section 1	Undervoltage Load Shedding Program Documentation	III.E.M1 Brief Description	Undervoltage load shedding program documentation.	
Section 1 Applicability	The Responsible Entity may be any of the following:  Load-serving Entity, Transmission Owner, Transmission Operator and Distribution Provider	III.E.M1 Applicability	UVLS owners and operators.	
Section 1 Requirements	R1-1. The Responsible Entity (Load-serving Entity, Transmission Owner, Transmission Operator and Distribution Provider) that owns or operates undervoltage loadshedding programs shall document their undervoltage loadshedding programs including descriptions of the following design details:  a. size of customer demand (load) blocks (% of	III.E.M1 Standard III.E.M1 Measurement	S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.  S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.  M1. Those entities owning or operating UVLS programs shall document their UVLS programs including descriptions of the following design details: size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>connected load)</p> <p>b. corresponding voltage set points</p> <p>c. relay and breaker operating times</p> <p>d. intentional delays</p> <p>e. related generation protection</p> <p>f. islanding schemes</p> <p>g. automatic load restoration schemes</p> <p>h. any other schemes that are part of or impact the undervoltage loadshedding programs.</p> <p>R1-2. The Responsible Entity that owns or operates undervoltage loadshedding programs shall provide documentation of the undervoltage load shedding program to the appropriate Regional Reliability Council(s) and NERC on request (five business days).</p>		Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request (five business days).	
Section 1 Measures	<p>M1-1. The Responsible Entity shall have documentation of its undervoltage load shedding program that includes all items specified in R1-1.</p> <p>M1-2. The Responsible Entity shall have evidence it provided the appropriate Regional Reliability Council(s) and NERC with documentation of its undervoltage load shedding program on request (five business days).</p>	III.E.M1 Items to be Measured		
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	<p>On request (five business days).</p> <p>Regional Reliability Council</p>	<p>III.E.M1 Timeframe</p> <p>III.E.M1 Compliance</p>	<p>On request (five business days).</p> <p>Regions</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
		Monitoring Responsibility		
Section 1 Levels of Non Compliance	Level 1 - Documentation of the undervoltage load shedding program was provided, but was incomplete.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Documentation of the undervoltage load shedding program was not provided.	III.E.M1 Levels of Non-compliance	Level 1 - Documentation of the UVLS program was provided, but was incomplete.  Level 2 - Not applicable.  Level 3 - Not applicable.  Level 4 - Documentation of the UVLS program was not provided.	





Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	request (within 30 business days).		request (within 30 business days).	
Section 2 Measures	<p>The Regional Reliability Council shall have an undervoltage load shedding program database that contains the items identified in Reliability Standard 068-R2-1.</p> <p>The Regional Reliability Council shall have evidence that it provided its current undervoltage load shedding program database to NERC as specified in Reliability Standard 068-R2-2.</p>	III.E.M2 Items to be Measured	UVLS program database.	
Section 2 Regional Differences	None Identified		None identified	
Section 2 Compliance Monitoring Process	<p>Database to be updated annually.</p> <p>Current database on request (30 business days).</p> <p>NERC</p>	<p>III.E.M2 Timeframe</p> <p>III.E.M2 Compliance Monitoring Responsibility</p>	<p>Database to be updated annually.</p> <p>Current database on request (30 business days).</p> <p>NERC</p>	
Section 2 Levels of Non-compliance	<p>Level 1 – An undervoltage load shedding program database was provided, but was incomplete.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 – An undervoltage load shedding program database was not provided.</p>	III.E.M2 Levels of Non-compliance	<p>Level 1 - A UVLS program database was provided, but was incomplete.</p> <p>Level 2 - Not applicable.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - A UVLS program database was not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	III.E.M3 Brief Description	Technical Assessment of the Design and Effectiveness of UVLS Program	
Section 3 Applicability	Load Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider	III.E.M3 Applicability	UVLS owners and operators.	
Section 3 Requirements	<p>R3-1. The Load-serving Entity, Transmission Owners, Transmission Operator, and Distribution Provider that owns or operates undervoltage load shedding programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of their undervoltage load shedding programs.</p> <p>This technical assessment shall include, but is not limited to:</p> <ul style="list-style-type: none"> <li>Coordination of the UVLS programs with other protection and control systems in the Region and with other Regions, as appropriate.</li> <li>Simulations that demonstrate that the UVLS programs performance is consistent with the Standard 51.</li> <li>A review of the voltage set points and timing.</li> </ul>	<p>III.E.M3 Standard</p> <p>III.E.M3 Measurement</p>	<p>S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.</p> <p>M3. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of their UVLS programs.</p> <p>This technical assessment shall include, but is not limited to:</p> <ul style="list-style-type: none"> <li>Coordination of the UVLS programs with other protection and control systems in the Region and with other Regions, as appropriate.</li> <li>Simulations that demonstrate that the UVLS programs performance is consistent with the I.A Standards.</li> <li>A review of the voltage set points and timing.</li> </ul> <p>Documentation of the current UVLS technical assessment</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	R3-2 The Load-serving Entity, Transmission Owners, Transmission Operator, and Distribution Provider that owns or operates undervoltage load shedding programs shall provide documentation of its current undervoltage load shedding program's technical assessment to the appropriate Regional Reliability Councils and NERC on request (30 days).		shall be provided to the appropriate Regions and NERC on request (30 days).	
Section 3 Measures	<p>M3-1. The Load-serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates undervoltage load shedding programs shall include the elements identified in Reliability Standard 068-R3-1.</p> <p>M3-2. The Load-serving Entity, Transmission Owners, Transmission Operator, and Distribution Provider that owns or operates undervoltage load shedding programs shall have evidence it provided documentation of its current undervoltage load shedding program's technical assessment to the Regional Reliability Councils and NERC as specified in Reliability Standard 068-R3-2.</p>	III.E.M3 Items to be Measured	Technical assessment of the design and effectiveness of UVLS programs.	
Section 3 Regional Differences	None identified		None identified	
Section 3 Compliance Monitoring Process	<p>Technical assessments every five years or as required by system changes.</p> <p>Current technical assessment on request (30 days).</p> <p>Regional Reliability Councils. Each Region shall report</p>	<p>III.E.M3 Timeframe</p> <p>III.E.M3 Compliance</p>	<p>Technical assessments every five years or as required by system changes.</p> <p>Current technical assessment on request (30 days).</p> <p>Region. Each Region shall report compliance and violations</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	compliance and violations to NERC via the NERC Compliance Reporting process.	Monitoring Responsibility	to NERC via the NERC Compliance Reporting process.	
Section 3 Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — A technical assessment of the undervoltage load shedding programs did not address one of the requirements listed in Reliability Standard 068-R2 or a technical assessment of the undervoltage load shedding programs was not provided.</p>	III.E.M3 Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — A technical assessment of the UVLS programs did not address one of the requirements listed in M3 above or a technical assessment of the UVLS programs was not provided.</p>	
Section 4	Under voltage load shedding system maintenance and testing.	III.E.M4 Brief Description	Under voltage load shedding system maintenance and testing.	
Section 4 Applicability	Load serving Entity, Transmission Owner, Transmission Operator and Distribution provider that owns an under voltage load shedding system	III.E.M4 Applicability	UVLS owners and operators.	
Section 4 Requirements		III.E.M4 Standard	S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R4-1. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns an under voltage load shedding system shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <p>a. Under voltage load shedding system identification shall include but is not limited to:</p> <ul style="list-style-type: none"> <li>• relays</li> <li>• instrument transformers</li> <li>• communications systems, where appropriate</li> <li>• batteries</li> </ul> <p>b. Documentation of maintenance and testing intervals and their basis</p> <p>c. Summary of testing procedure</p> <p>d. Schedule for system testing</p> <p>e. Schedule for system maintenance</p> <p>f. Date last tested/maintained</p> <p>R4-2. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns an under voltage load shedding system shall provide documentation of the program and its implementation to the appropriate Regions and NERC on request (within 30 days).</p>	III.E.M4 Measurement	<p>M4. Under voltage load shedding system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <p>a. Under voltage load shedding system identification shall include but is not limited to:</p> <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> <p>b. Documentation of maintenance and testing intervals and their basis</p> <p>c. Summary of testing procedure</p> <p>d. Schedule for system testing</p> <p>e. Schedule for system maintenance</p> <p>f. Date last tested/maintained</p> <p>Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).</p>	
Section 4 Measures	M4-1. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns an under voltage load shedding system shall have documentation that its undervoltage load shedding equipment maintenance program conforms with	III.E.M4 Items to be Measured	Each entity's UVLS equipment maintenance program.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Standard 068-R4-1. M4-2. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns an under voltage load shedding system shall have evidence it provided documentation of its undervoltage load shedding maintenance program and its implementation as specified in Standard 068-R4-2.			
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Council	III.E.M4 Timeframe  III.E.M4 Compliance Monitoring Responsibility	On request (30 business days).  Region	
Section 4 Levels of Non Compliance	Level 1 - Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 - Compliance documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 - Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.		Level 1 - Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.  Level 2 - Compliance documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.  Level 3 - Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.  Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 5	Analysis and Documentation of Undervoltage Load Shedding Program Performance	III.E.M5 Brief Description	Analysis and Documentation of UVLS Program Performance	
Section 5 Applicability	Load-serving Entity, Transmission Owner, Transmission Operator, Distribution Provider that owns or operates an undervoltage load shedding program	III.E.M5 Applicability	UVLS owners and operators.	
Section 5 Requirements	<p>R5-1. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns or operates an undervoltage load shedding program shall analyze and document all undervoltage load shedding operations, misoperations, and failures to operate. Documentation of the analysis shall include a review of the undervoltage load shedding set points and tripping times and a summary of the findings.</p> <p>R5-2. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns or operates an undervoltage load shedding program shall provide documentation of its analysis of undervoltage load shedding operations, misoperations, and failures to operate, to the appropriate Regional Reliability Councils and NERC on request (30 business days).</p>	<p>III.E.M5 Standard</p> <p>III.E.M5 Measurement</p>	<p>S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.</p> <p>M5. Those entities owning or operating an UVLS program shall analyze and document all UVLS operations, misoperations, and failures to operate. Documentation of the analysis shall include a review of the UVLS set points and tripping times and a summary of the findings. This documentation shall be provided to the appropriate Regions and NERC on request (30 business days).</p>	
Section 5 Measures	<p>M5-1. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns or operates an undervoltage load shedding program shall have documentation to show that its analysis of undervoltage load shedding operations, misoperations and failures to operate as specified in Reliability Standard 069-R5-1.</p> <p>M5-2. The Load-serving Entity, Transmission Owner, and Distribution Provider that owns or operates an undervoltage load</p>	III.E.M5 Items to be Measured	Analysis of UVLS program performance.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	shedding program shall have evidence that it provided documentation of its analysis of undervoltage load shedding operations, misoperations, and failures to operate as specified in Reliability Standard 069-R5-2.			
Section 5 Regional Differences	None identified		None identified	
Section 5 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Council	III.E.M5 Timeframe  III.E.M5 Compliance Monitoring Responsibility	On request (30 business days).  Region	
Section 5 Levels of Non Compliance	Level 1 - An analysis of undervoltage load shedding operations, misoperations, and failures to operate was provided but was incomplete. Level 2 - Not applicable. Level 3 - Not applicable. Level 4 - An analysis of undervoltage load shedding program performance was not provided.	III.E.M5 Levels of Non-compliance	Level 1 - An analysis of UVLS operations, misoperations, and failures to operate was provided but was incomplete. Level 2 - Not applicable. Level 3 - Not applicable. Level 4 - An analysis of UVLS program performance was not provided.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	069	Compliance Template III.F.M1 III.F.M2 III.F.M3 III.F.M4 III.F.M5 III.F.M6	III. System Protection and Control  F. Special Protection Systems	
Title	Special Protection Systems	Section	III. System Protection and Control  F. Special Protection Systems	Combined the six III.F Compliance Templates into one standard covering Special Protection Systems. Avoids duplication and multiple standards.
		Introduction III.F	<p>Introduction</p> <p>A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings.</p> <p>The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the NERC</p>	The introduction material should be moved to another document such as a technical guide. This information is important in that it defines a SPS and should not be lost.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			<p>Planning Standards must ensure that the SPS is highly reliable.</p> <p>Examples of SPS misoperation include, but are not limited to, the following:</p> <ol style="list-style-type: none"> <li>1. The SPS does not operate as intended.</li> <li>2. The SPS fails to operate when required.</li> <li>3. The SPS operates when not required.</li> </ol>	
Purpose	To ensure that all Special Protection Systems are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.			The purpose was derived from Standards S1,S2,S3,S4,and S5
Effective Date	February 8, 2005	Approvals	III.A.M1- NERC BOT approved -- October 16, 2001 III.A.M2- NERC BOT approved -- October 16, 2001 III.A.M3 - NERC BOT approved -- October 16, 2001 III.A.M4 - NERC BOT approved -- October 16, 2001 III.A.M5 - NERC BOT approved -- October 16, 2001 III.A.M6 - CTTF Revised Compliance Template, NERC BOT Approved – April 2, 2004	
Standard Applicability	Section 1 – Regional Reliability Council Section 2 – Regional Reliability Council Section 3 – Regional Reliability Council Section 4 – Transmission Owner, Generator Owner, and	Applicability	M1 – Regions  M2 – Regions  M3 – Regions	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Distribution Providers that own a Special Protection System Section 5 – Transmission Owner, Generator Owner, and Distribution Providers that own a Special Protection System Section 6 – Transmission Owner, Generator Owner, and Distribution Providers that own a Special Protection System		M4 – SPS Owners M5 – SPS Owners M6 – SPS Owners	
Section 1	Special Protection System Procedure	III.F.M1  Brief Description	Establish and document Regional review procedures for special protection system (SPS) installations.	
Section 1 Applicability	Regional Reliability Council	III.F.M1 Applicability to	Regions	
Section 1 Requirements		III.F.M1  Standard	S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.  S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed	R1-1 restates M1

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R1-1. Each Regional Reliability Council with a Transmission Owner, Generator Owner, or Distribution Providers(s) that uses or is planning to use a Special Protection System shall have a documented Regional Reliability Council review procedure to ensure the Special Protection System complies with Regional Reliability Council criteria and NERC Reliability Standards. The Regional Reliability Council review procedure shall include:</p> <ol style="list-style-type: none"> <li>1) Description of the process for submitting a proposed Special Protection System for Regional Reliability Council review.</li> <li>2) Requirements to provide data that describes design, operation, and modeling of a Special Protection System.</li> <li>3) Requirements to demonstrate that the Special Protection System shall be designed so that a single Special Protection System component failure, when the Special Protection System was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in sections 1,2,3 and 3 of</li> </ol>	<p>III.F.M1 Measure</p>	<p>Category C.</p> <p>S3. SPS installations shall be coordinated with other protection and control systems.</p> <p>S4. All SPS misoperations shall be analyzed for cause and corrective action.</p> <p>M1. Each Region whose members use or are planning to use an SPS shall have a documented Regional review procedure to ensure the SPS complies with Regional criteria and NERC Planning Standards . The Regional review procedure shall include:</p> <ol style="list-style-type: none"> <li>1) Description of the process for submitting a proposed SPS for Regional review.</li> <li>2) Requirements to provide data that describes design, operation, and modeling of an SPS.</li> <li>3) Requirements to demonstrate that the SPS design will meet above SPS Standards S1 and S2.</li> <li>4) Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional emergency procedures.</li> <li>5) Regional definition of misoperation.</li> <li>6) Requirements for analysis and documentation of corrective action plans for all SPS misoperations.</li> <li>7) Identification of the Regional group responsible for the Region’s review procedure and the process for Regional approval of the procedure.</li> </ol>	<p>Existing #3 was subdivided and instead of cross referencing existing Planning Standards, the language from S1 and S2 was copied into the new R1-1 item 3 and item 4.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Standard 051.</p> <p>4) Requirements to demonstrate that the inadvertent operation of a Special Protection System shall meet the same performance requirement (Section 1,2, and 3 of Reliability Standard 051) as that required of the contingency for which it was designed, and not exceed Section 3 (Reliability Standard 051)</p> <p>5) Requirements to demonstrate the proposed Special Protection System will coordinate with other protection and control systems and applicable Regional Reliability Council emergency procedures.</p> <p>6) Regional Reliability Council definition of misoperation.</p> <p>7) Requirements for analysis and documentation of corrective action plans for all Special Protection System misoperations.</p> <p>8) Identification of the Regional Reliability Council group responsible for the Regional Reliability Council’s review procedure and the process for Regional Reliability Council approval of the procedure.</p> <p>9) Determination, as appropriate, of maintenance and testing requirements.</p> <p>R1-2. The Regional Reliability Council shall provide affected Regional Reliability Councils and NERC with documentation of the Regional Reliability Council’s Special Protection System review procedure on request (within 30 days).</p>		<p>8) Determination, as appropriate, of maintenance and testing requirements.</p> <p>Documentation of the Regional SPS review procedure shall be provided to affected Regions and NERC, on request (within 30 days).</p>	<p>R1-2 restates the last paragraph of M1</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 1 Measures	<p>M1-1. The Regional Reliability Council whose members use or are planning to use a Special Protection System shall have a documented Regional Reliability Council review procedure as defined in Reliability Standard 069-R1.</p> <p>M1-2. The Regional Reliability Council shall have evidence it provided affected Regional Reliability Councils and NERC with documentation of its Special Protection System review procedure on request (within 30 days).</p>	III.F.M1 Items to be Measured	Regional review procedure for assessing SPSs to ensure compliance with NERC Planning Standards and Regional criteria.	
Section 1 Regional Differences	Not Identified		Not Identified	
Section 1 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>NERC</p>	<p>III.F.M1 Timeframe</p> <p>III.F.M1 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 Documentation of the Regional Reliability Council's procedure is missing one of the items listed in Reliability Standard 069- R1-1.</p> <p>Level 2 Documentation of the Regional Reliability Council's procedure is missing two of the items listed in Reliability Standard 069-R1-1.</p> <p>Level 3 Documentation of the Regional Reliability Council's procedure is missing three of the items listed in Reliability</p>	III.F.M1 Levels of Non-Compliance	<p>Level 1 Documentation of the Regional procedure is missing one of the items listed in III.F. M1.</p> <p>Level 2 Documentation of the Regional procedure is missing two of the items listed in III.F. M1.</p> <p>Level 3 Documentation of the Regional procedure is missing three of the items listed in III.F. M1.</p> <p>Level 4 Documentation of the Regional procedure was not provided or is missing four or more of the items listed in</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Standard 069-R1-1.</p> <p>Level 4 Documentation of the Regional Reliability Council's procedure was not provided or is missing four or more of the items listed in Reliability Standard 069-R1-1.</p>		III.F. M1.	
Section 2	Special Protection System Database	III.F.M2 Brief Description		
Section 2 Applicability	Regional Reliability Council	III.F.M2 Applicability to	Regions	
Section 2 Requirements	<p>R2-1. A Regional Reliability Council that has a Transmission Owner, Generator Owner, or Distribution Provider with a Special Protection System installed shall maintain a</p>	<p>III.F.M2 Standard</p> <p>III.F.M2 Measure</p>	<p>S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.</p> <p>S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.</p> <p>S3. SPS installations shall be coordinated with other protection and control systems.</p>	<p>R2-1 restates M2</p> <p>R2-2 restates the last paragraph of M2 incorporating functional</p>



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Special Protection System database. The database shall include the following types of information:</p> <ol style="list-style-type: none"> <li>1) Design Objectives – Contingencies and system conditions for which the Special Protection System was designed,</li> <li>2) Operation – The actions taken by the Special Protection System in response to disturbance conditions, and</li> <li>3) Modeling – Information on detection logic or relay settings that control operation of the Special Protection System.</li> </ol> <p>R2-2. The Regional Reliability Council shall provide to affected Regional Reliability Council(s) and NERC documentation of its database or the information therein on request (within 30 days).</p>		<p>M2. A Region that has a member with an SPS installed shall maintain an SPS database. The database shall include the following types of information:</p> <ol style="list-style-type: none"> <li>1. Design Objectives – Contingencies and system conditions for which the SPS was designed,</li> <li>2. Operation – The actions taken by the SPS in response to disturbance conditions, and</li> <li>3. Modeling – Information on detection logic or relay settings that control operation of the SPS.</li> </ol> <p>Documentation of the Regional database or the information therein shall be provided to affected Regions and NERC, on request (within 30 days).</p>	model terminology
Section 2 Measures	<p>M2-1. The Regional Reliability Council that has a Transmission Owner, Generator Owner, or Distribution Providers with a Special Protection System installed, shall have a Special Protection System database as defined in Section 2 R1 of this Reliability Standard.</p> <p>M2-2. The Regional Reliability Council shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Council(s) and NERC on request (within 30 days).</p>	III.F.M2 Items to be Measured	Regional database of SPS installations.	Suggested Measures for Requirement R2-1 and R2-2
Section 2 Regional Differences	Not Identified		Not Identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Compliance Monitoring Process	On request (within 30 days)  NERC	III.F.M2 Timeframe  III.F.M2 Compliance Monitoring Responsibility	On request (within 30 days)  NERC	
Section 2 Levels of Non Compliance	<p>Level 1 The Regional Reliability Council’s database is missing one of the items listed in Reliability Standard 069-R2-1.</p> <p>Level 2 The Regional Reliability Council’s database is missing two of the items listed in Reliability Standard 069-R2-1.</p> <p>Level 3 Not applicable.</p> <p>Level 4 The Regional Reliability Council’s database was not provided or is missing all of the elements listed in Reliability Standard 069-R2-1.</p>	III.F.M2 Levels of Non- Compliance	<p>Level 1 Regional database is missing one of the items listed in III.F. M2.</p> <p>Level 2 Regional database is missing two of the items listed in III.F. M2.</p> <p>Level 3 Not applicable.</p> <p>Level 4 Regional database was not provided or is missing all of the elements listed in III.F. M2.</p>	Changed references to match the requirements in the new standard.
Section 3	Special Protection System Assessment	III.F.M3 Brief Description	System Assessment	
Section 3 Applicability	Regional Reliability Council	III.F.M3 Applicability to	Regions	
Section 3 Requirements		III.F.M3  Standard	S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of	M3 was divided into three requirements R3-1, R3-2, and R3-3 for readability.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>R3-1. The Regional Reliability Council shall assess the operation, coordination, and effectiveness of all Special Protection Systems installed in its region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.</p> <p>R3-2. The Regional Reliability Council shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all Special Protection Systems installed in its region to affected Reliability Authorities or NERC, on request (within 30 days).</p> <p>R3-3. The documentation of the Regional Reliability Council's Special Protection System assessment shall include the following elements:</p>	III.F.M3 Measure	<p>Table 1 of the I.A Standards on Transmission Systems.</p> <p>S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.</p> <p>S3. SPS installations shall be coordinated with other protection and control systems.</p> <p>M3. A Region shall assess the operation, coordination, and effectiveness of all SPSs installed in the Region at least once every five years for compliance with NERC Planning Standards and Regional criteria. The Regions shall provide either a summary report or a detailed report of this assessment to affected Regions or NERC, on request (within 30 days). The documentation of the Regional SPS assessment shall include the following elements:</p> <ol style="list-style-type: none"> <li>1) Identification of group conducting the assessment and the date the assessment was performed.</li> <li>2) Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.</li> <li>3) Identification of SPSs that were found not to</li> </ol>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<ol style="list-style-type: none"> <li>1) Identification of group conducting the assessment and the date the assessment was performed.</li> <li>2) Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.</li> <li>3) Identification of Special Protection Systems that were found not to comply with NERC Standards and Regional Reliability Council criteria.</li> <li>4) Discussion of any coordination problems found between a Special Protection System and other protection and control systems.</li> <li>5) Provide corrective action plans for non-compliant Special Protection Systems.</li> </ol>		<p>comply with NERC Planning Standards and Regional criteria.</p> <ol style="list-style-type: none"> <li>4) Discussion of any coordination problems found between an SPS and other protection and control systems.</li> <li>5) Provide corrective action plans for non-compliant SPSs.</li> </ol>	
Section 3 Measures	<p>M3-1. The Regional Reliability Council shall assess the operation, coordination, and effectiveness of all Special Protection Systems installed in its region at least once every five years for compliance with NERC Standards and Regional criteria.</p> <p>M3-2. The Regional Reliability Council shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Councils or NERC, on request (within 30 days).</p> <p>M3-3. The Regional Reliability Council's documentation of the Special Protection System assessment shall include all elements as defined in Section 3 of Reliability Standard 069-R3.</p>	III.F.M3 Items to be Measured	Result of Regional reviews for SPS compliance with NERC Planning Standards and Regional criteria.	Suggested Measures for Requirement R3-1, R3-2, and R3-3
Section 3 Regional Differences	Not Identified		Not Identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3 Compliance Monitoring Process	On request (within 30 days)  NERC	III.F.M3 Timeframe  III.F.M3 Compliance Monitoring Responsibility	On request (within 30 days)  NERC	
Section 3 Levels of Non Compliance	<p>Level The summary (or detailed) Regional Reliability Council Special Protection System assessment is missing one of the items listed in Reliability Standard 069-R3-3.</p> <p>Level 2 The summary (or detailed) Regional Reliability Council Special Protection System assessment is missing two of the items listed in Reliability Standard 069-R3-3.</p> <p>Level 3 The Regional Reliability Council’s summary (or detailed) Regional Reliability Council Special Protection System assessment is missing three of the items listed in Reliability Standard 069-R3-3.</p> <p>Level 4 The Regional Reliability Council’s summary (or detailed) Regional Reliability Council Special Protection System assessment is missing more than three of the items listed in Reliability Standard 069-R3-3 or was not provided.</p>	III.F.M3 Levels of Non- Compliance	<p>Level 1 The summary (or detailed) Regional SPS assessment is missing one of the items listed in III.F. M3.</p> <p>Level 2 The summary (or detailed) Regional SPS assessment is missing two of the items listed in III.F. M3.</p> <p>Level 3 The summary (or detailed) Regional SPS assessment is missing three of the items listed in III.F. M3.</p> <p>Level 4 The summary (or detailed) Regional SPS assessment is missing more than three of the items listed in III.F. M3 or was not provided.</p>	Changed references to match the requirements in the new standard.
Section 4	Special Protection System Data and Documentation	III.F.M4 Brief Description	SPS Data and Documentation	
Section 4 Applicability	Transmission Owner, Generator Owner, and Distribution	III.F.M4 Applicability	SPS Owners	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Provider that owns a Special Protection System.	to		
Section 4 Requirements	<p>R4-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall maintain a list of and provide data for existing and proposed Special Protection Systems as defined in Reliability Standard 069-R2-1.</p> <p>R4-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it reviewed new or functionally modified Special Protection Systems in accordance with the Regional Reliability Council's procedures as defined in Reliability Standard 069-R1-1 prior to being placed in service.</p>	<p>III.F.M4 Standard</p> <p>III.F.M4 Measure</p>	<p>S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.</p> <p>S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.</p> <p>S3. SPS installations shall be coordinated with other protection and control systems.</p> <p>M4. SPS owners shall maintain a list of and provide data for existing and proposed SPSs as defined in Measurement III.F. S1-S3, M2. New or functionally modified SPSs shall be reviewed in accordance with the Regional procedures as defined in Measurement III.F. S1-S4, M1 prior to being placed in service.</p> <p>Documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Planning Standards and Regional criteria shall be provided to affected Regions and NERC, on request (within</p>	<p>M4 was divided into two requirements R4-1 and R4-2 for readability</p> <p>R4-1 and R4-2, restate M4 incorporating functional model terminology</p> <p>R4-3 restates the last paragraph of M4 incorporating functional model terminology</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	R4-3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall provide documentation of Special Protection System data and the results of studies that show compliance of new or functionally modified Special Protection Systems with NERC Standards and Regional Reliability Council criteria to affected Regional Reliability Councils and NERC, on request (within 30 days).		30 days).	
Section 4 Measures	<p>M4-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall maintain a list of and provide data for existing and proposed Special Protection Systems as defined in Reliability Standard 069-R2-1.</p> <p>M4-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it reviewed new or functionally modified Special Protection Systems in accordance with the Regional Reliability Council's procedures as defined in Reliability Standard 069-R1-1 prior to being placed in service.</p> <p>M4-3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it provided documentation of Special Protection System data and the results of studies that show compliance of new or functionally modified Special Protection Systems with NERC Standards and Regional Reliability Council criteria to affected Regional Reliability Councils and NERC, on request (within 30 days).</p>	<p>III.F.M4</p> <p>Items to be Measured</p>	SPS data and results of studies that show SPS compliance with NERC Planning Standards and Regional criteria.	
Section 4	Not Identified		Not Identified	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Regional Differences				
Section 4 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>Regional Reliability Council</p>	<p>III.F.M4 Timeframe</p> <p>III.F.M4 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>Regions</p>	
Section 4 Levels of Non Compliance	<p>Level 1 - Special Protection System provided Special Protection System data, but was incomplete according to the Regional Reliability Council Special Protection System database</p> <p>Level 2 - Special Protection System provided results of studies that show compliance of new or functionally modified Special Protection Systems with the NERC Planning Standards and Regional Reliability Council criteria, but were incomplete according to the Regional Reliability Council procedures for Reliability Standard 069-R1-1.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - No Special Protection System data was provided in accordance with Regional Reliability Council Special Protection System database requirements for Standard 069-R1-1 , or the results of studies that show compliance of new or functionally modified Special Protection Systems with the NERC Reliability Standards and Regional Reliability Council criteria were not provided in accordance with Regional Reliability Council procedures for Reliability Standard 069-R1-1.</p>	<p>III.F.M4 Levels of Non- Compliance</p>	<p>Level 1 - SPS data was provided, but was incomplete according to the Regional SPS database</p> <p>Level 2 - Results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional criteria were provided, but were incomplete according to the Regional procedures for III.F. M1.</p> <p>Level 3 - Not applicable.</p> <p>Level 4 - No SPS data was provided in accordance with Regional SPS database requirements for III.F. M2, or the results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional criteria were not provided in accordance with Regional procedures for III.F. M1.</p>	<p>Changed references to match the requirements in the new standard.</p>



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 5	Special Protection System Misoperations	III.F.M5 Brief Description	Special Protection System Misoperations	
Section 5 Applicability	Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System	III.F.M5 Applicability to	SPS Owners	
Section 5 Requirements	<p>R5-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall analyze its Special Protection System operations and maintain a record of all misoperations in accordance with Regional Reliability Council procedures in Reliability Standard 069- R1-1.</p> <p>R5-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall take corrective actions to avoid future misoperations.</p> <p>R5-3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall provide documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Council and NERC, on request (within 90 days).</p>	<p>III.F.M5 Standard</p> <p>III.F.M5 Measure</p>	<p>S4. All SPS misoperations shall be analyzed for cause and corrective action.</p> <p>M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations.</p> <p>Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days).</p>	<p>M5 was divided into two requirements R5-1 and R5-2 for readability</p> <p>R5-1 and R5-2, restate M5 incorporating functional model terminology</p> <p>R5-3 restates the last paragraph of M5 incorporating functional model terminology</p>
Section 5 Measures	M5-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it analyzed Special Protection System operations and maintains a record of	III.F.M5 Items to be Measured	Documentation of protection system misoperations, analyses, and corrective actions.	Suggested Measures for Requirement R5-1, R5-2, and R5-3

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>all misoperations in accordance with Regional Reliability Council procedures in Reliability Standard 069-R5-1.</p> <p>M5-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it took corrective actions to avoid future misoperations.</p> <p>M5-3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Council and NERC, on request (within 90 days).</p>			
Section 5 Regional Differences	Not Identified		Not Identified	
Section 5 Compliance Monitoring Process	<p>On request (within 90 days of the incident or on request (within 30 days) if requested more than 90 days after the incident)</p> <p>Regional Reliability Council</p>	<p>III.F.M5 Timeframe</p> <p>III.F.M5 Compliance Monitoring Responsibility</p>	<p>On request (within 90 days of the incident or on request (within 30 days) if requested more than 90 days after the incident)</p> <p>Regions</p>	
Section 5 Levels of Non Compliance	<p>Level 1 Documentation of Special Protection System misoperations is complete but documentation of corrective actions taken for all identified Special Protection System misoperations is incomplete.</p> <p>Level 2 Documentation of corrective actions taken for Special Protection System misoperations is complete but documentation</p>	<p>III.F.M5 Levels of Non-Compliance</p>	<p>Level 1 Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.</p> <p>Level 2 Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>of Special Protection System misoperations is incomplete.</p> <p>Level 3 - Documentation of Special Protection System misoperations and corrective actions is incomplete.</p> <p>Level 4 - No documentation of Special Protection System misoperations or corrective actions.</p>		<p>Level 3 Documentation of SPS misoperations and corrective actions is incomplete.</p> <p>Level 4 No documentation of SPS misoperations or corrective actions was provided.</p>	
Section 6	Special Protection System Maintenance and Testing	III.F.M6 Brief Description	Special Protection System Maintenance and Testing	
Section 6 Applicability	Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System	III.F.M6 Applicability to	Special Protection System owners whose special protection systems support the reliability of the bulk power electric system.	
Section 6 Requirements	<p>R6-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Special Protection System identification shall include but is not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing intervals and their basis</li> </ul>	III.F.M6  Measure	<p>S5 Special protection system maintenance and testing programs shall be developed and implemented.</p> <p>M6. Special Protection System owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <ul style="list-style-type: none"> <li>a. Special Protection System identification shall include but is not limited to: <ul style="list-style-type: none"> <li>▪ relays</li> <li>▪ instrument transformers</li> <li>▪ communications systems, where appropriate</li> <li>▪ batteries</li> </ul> </li> <li>b. Documentation of maintenance and testing</li> </ul>	R6-1 restates Measure M6 incorporating functional model terminology

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<ul style="list-style-type: none"> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>R6-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall provide documentation of the program and its implementation to the appropriate Regional Reliability Councils and NERC on request (within 30 days).</p>		<p>intervals and their basis</p> <ul style="list-style-type: none"> <li>c. Summary of testing procedure</li> <li>d. Schedule for system testing</li> <li>e. Schedule for system maintenance</li> <li>f. Date last tested/maintained</li> </ul> <p>Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).</p>	R6-2 restates the last paragraph of M6
Section 6 Measures	<p>M6-1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard 069-R6-1.</p> <p>M6-2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a Special Protection System shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Councils and NERC on request (within 30 days).</p>	<p>III.F.M6</p> <p>Items to be Measured</p>	Documentation of the SPS maintenance and testing program.	Suggested Measures for Requirement R6-1, R6-2, and R6-3
Section 6 Regional Differences	Not Identified		Not Identified	
Section 6 Compliance Monitoring Process	<p>On request (within 30 days)</p> <p>Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>	<p>III.F.M6 Timeline</p> <p>III.F.M6 Compliance Monitoring Responsibility</p>	<p>On request (within 30 days)</p> <p>Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 6 Levels of Non Compliance	<p>Level 1 - Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.</p> <p>Level 2 - Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.</p> <p>Level 3 - Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.</p> <p>Level 4 - Documentation of the maintenance and testing program, or its implementation, was not provided.</p>	III.F.M6 Levels of Non- Compliance	<p>Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.</p> <p>Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.</p> <p>Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.</p> <p>Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	070	Compliance Templates IV.A. M1 IV.A. M2 IV.A. M3 IV.A. M4	IV. System Restoration A. System Blackstart Capability	
Title	System Blackstart Capability	Section	IV. System Restoration A. System Blackstart Capability	
Purpose	A system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated regional system restoration plans.	Introduction	<p>Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators. They must be able to self-start without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators. Generators that can safely reject load down to their auxiliary load are another form of blackstart generator that can aid system restoration.</p> <p>From a planning perspective, a system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional system restoration plans.</p>	Purpose was taken from the second paragraph of the Introduction to the associated Compliance Templates
Effective Date	February 8, 2005	Approval Dates	IV.A.M1 CTTF Revised Compliance Template, NERC BOT Approved – April 2, 2004 IV.A.M2 Approved for field testing in Phase III October 9, 2000 IV.A.M3 Approved for field testing in Phase III - October	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			9, 2000 IV.A.M4 CTTF Revised Compliance Template, NERC BOT Approved – April 2, 2004	
Standard Applicability	Section 1 - Regional Reliability Council Section 2 - Transmission Operators Section 3 - Transmission Operators Section 4 – Generation Owners or Generator Operators	Standard Applicable to	IV.A. M1 - Regional Reliability Councils IV.A. M2 - Transmission Operators IV.A. M3 - Transmission Operators IV.A. M4 – Operators or owners of blackstart generating units	Applicability may apply to both Generator Owners and Generator Operators in some instances. This issue needs clarification in the Functional Model.
Section 1	Establish, maintain, and document a regional blackstart capability plan.	IV.A.M1 Brief Description	Establish, maintain, and document a Regional blackstart capability plan	
Section 1 Applicability	Regional Reliability Council	IV.A.M1 Applicable to	Regional Reliability Councils	
Section 1 Requirements	R1-1. Each Regional Reliability Council shall establish and maintain a system blackstart capability plan, as part of an overall coordinated regional system restoration plan, that shall include requirements for verification through analysis how system blackstart generating units shall perform their	IV.A.M1 Standard  IV.A.M1 Measure	S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.  M1. Each Region shall establish and maintain a system blackstart capability plan, as part of an overall coordinated Regional system restoration plan, that	The requirements of the first sentence of S1 are also included in the requirements of the first paragraph in M1.  The requirements of second sentence of S1 are not included in M1 and, therefore, this sentence is added to Requirement R1-1

<sup>1</sup> A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Regional Reliability Council in accordance with the regional Blackstart Plan or that unit will no longer be considered blackstart.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>intended functions and shall be sufficient to meet system restoration plan expectations.</p> <p>The Regional Reliability Council shall coordinate with and among other Regional Reliability Councils as appropriate in the development of its blackstart capability plan(s).as appropriate.</p> <p>The blackstart capability plan shall include:</p> <ol style="list-style-type: none"> <li>1 A requirement to have a database that contains all blackstart generators<sup>1</sup> designated for use in a Restoration Plan within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, MW capacity, type of unit, latest date of test, and starting method.</li> <li>2 A requirement to demonstrate that blackstart units perform their intended functions as required in the Reliability Authority’s system restoration plan. This requirement can be met either through simulation or testing. The blackstart plan must consider the availability of designated blackstart plan units and initial transmission switching requirements.</li> <li>3 Blackstart unit testing requirements including, but not limited to: <ul style="list-style-type: none"> <li>▪ Testing frequency (minimum of one third of the units each year).</li> <li>▪ Type of test required, including the requirement to start when isolated from the system</li> <li>▪ Minimum duration of tests</li> </ul> </li> </ol>		<p>shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet system restoration plan expectations.</p> <p>The blackstart capability plan shall include:</p> <ol style="list-style-type: none"> <li>1. A requirement to have a database that contains all blackstart generators designated for use in a Restoration Plan within the respective areas and a requirement to update the database on an annual basis. The database shall include the name, location, MW capacity, type of unit, latest date of test, and starting method.</li> <li>2. A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional system restoration plan through simulation or testing. The blackstart plan must consider the availability of designated blackstart plan units and initial transmission switching requirements.</li> <li>3. Blackstart unit testing requirements including, but not limited to: <ul style="list-style-type: none"> <li>▪ Testing frequency (minimum of one third of the units each year).</li> <li>▪ Type of test required, including the requirement to start when isolated from the</li> </ul> </li> </ol>	<p>R1-1 number 3 (blackstart unit testing requirements) needs clarification in Version 1.</p>



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>4 A requirement to review and update the regional blackstart capability plan at least every five years</p> <p>R1-2. The Regional Reliability Council shall provide documentation of its system blackstart capability plans to NERC within 30 business days of a request.</p>		<p>system</p> <ul style="list-style-type: none"> <li>Minimum duration of tests</li> </ul> <p>4. A requirement to review and update the Regional blackstart capability plan at least every five years.</p> <p>Documentation of system blackstart capability plans shall be provided to NERC on request (30 days).</p>	R1-2 changed “days” to “business days”
Section 1 Measures	<p>M1 The Regional Reliability Council ’s blackstart capability plan shall include all four of the requirements in Reliability Standard 070-R1-1.</p> <p>M2 – The Regional Reliability Council shall have evidence it provided its blackstart capability plan in accordance with Reliability Standard 070-R1-2.</p>	IV.A.M1 Items to be Measured	A Regional plan for blackstart capability.	
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p>Current regional blackstart capability plan: on request (30 days)</p> <p>NERC</p>	<p>Timeframe</p> <p>Compliance Monitoring Responsibility</p>	<p>Current Regional blackstart capability plan: on request (30 days)</p> <p>NERC</p>	
Section 1 Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — The Regional Reliability Council’s blackstart generating unit capability plan was incomplete in one</p>	IV.A.M1 Levels of Non-Compliance	<p>Level 1 — N/A</p> <p>Level 2 — The Region’s blackstart generating unit capability plan was incomplete in one of the four</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>of the four requirements defined above in Reliability Standard 070-R1-1.</p> <p>Level 3 — N/A</p> <p>Level 4 — The Regional Reliability Council’s blackstart generating unit capability plan was not provided (Reliability Standard 070-R2-1), or was incomplete in two or more of the four requirements defined above in Reliability Standard 070-R1-1.</p>		<p>requirements defined above in Measure M1</p> <p>Level 3 — N/A</p> <p>Level 4 — The Region’s blackstart generating unit capability plan was not provided, or incomplete in two or more of the four requirements defined above in Measure M1.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments

Section 2	Establish, maintain, and document a regional blackstart capability plan.	IV.A.M2 Brief Description	Establish, maintain, and document a Regional blackstart capability plan.	
Section 2 Applicability	Transmission Operator	IV.A.M2 Applicable to	Transmission Operators	
Section 2 Requirements	<p>R2-1. Each Transmission Operator shall verify that the number, size, and location of system blackstart generating units are sufficient to meet regional restoration plan expectations. The Transmission Operator of each system shall demonstrate, through simulation or testing, that blackstart generating unit(s) in its area can perform their intended functions as required in the regional restoration plan. (Section 1 of this reliability standard) Such simulation or testing shall be performed at least every five years.</p> <p>R2-2. Each Transmission Operator shall provide documentation of its most current simulations or tests to the Regional Reliability Councils and NERC on request (within 30 business days).</p>	IV.A.M2 Standard  IV.A.M2 Measure	<p>S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.</p> <p>M2. Each transmission operator shall verify that the number, size, and location of system blackstart generating units are sufficient to meet Regional restoration plan expectations. The transmission operator of each system shall demonstrate, through simulation or testing, that its blackstart generating unit(s) can perform their intended functions as required in the Regional restoration plan (Standard IV.A. S1). Such simulation or testing shall be performed at least every five years.</p> <p>Documentation of the most current simulations or tests shall be provided to the Regions and NERC on request (30</p>	<p>R2-2 Added language to specify what entity is responsible for this requirement.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			business days).	
Section 2 Measures	<p>M2-1. The Transmission Operator shall provide documentation that the blackstart units in its area are sufficient to meet the requirements of Standard 070-R2-1.</p> <p>M2-2. The Transmission Owner shall have evidence it provided its test results in accordance with Standard 070-R2-2.</p>	IV.A.M2 Items to be Measured	Simulation or test results to demonstrate that blackstart generating unit(s) can perform their intended functions in system restoration.	Without the addition of M2-2, the levels of non-compliance can't be linked to the measures. The Levels of non-compliance assess both the test results as well as whether the results were provided.
Section 2 Regional Differences	None identified.		None identified.	
Section 2 Compliance Section 2 Monitoring Process	<p>Simulation or testing of blackstart capability units: Every five years.</p> <p>Documentation of the most current simulations or tests: on request (30 business days)</p> <p>Regional Reliability Council</p>	IV.A.M2 Timeframe  Compliance Monitoring Responsibility	<p>Simulation or testing of blackstart capability units: Every five years.</p> <p>Documentation of the most current simulations or tests: on request (30 business days)</p> <p>Regions</p>	
Section 2 Levels of Non Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — The Transmission Operator's simulation or test results demonstrating that blackstart generating units can perform their intended functions were not provided, or the results were not compliant with the regional restoration plan.</p>	IV.A.M2 Levels of Non-Compliance	<p>Level 1 — N/A</p> <p>Level 2 — N/A</p> <p>Level 3 — N/A</p> <p>Level 4 — The transmission operator's simulation or test results demonstrating that blackstart generating units can perform their intended functions were not provided, or the results were not compliant with the Regional restoration plan.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 3	Diagram the number, size, and location of system blackstart generating units and the initial transmission switching requirements.	IV.A.M3 Brief Description	Diagram the number, size, and location of system blackstart generating units and the initial transmission switching requirements.	
Section 3 Applicability	Transmission Operator	IV.A.M3 Applicable to	Transmission Operators	
Section 3 Requirements	<p>R3-1. Each Transmission Operator<sup>2</sup> shall have on file diagrams showing the location of each blackstart generating unit that is part of the regional blackstart capability plan (Reliability Standard 070-R1-1). The diagrams shall be reviewed and updated annually or when system changes occur. Where applicable, primary and secondary cranking paths associated with each blackstart generating unit and the units to be restarted shall be identified on the diagrams.</p> <p>R3-2. The Transmission Operator shall provide current diagrams to the Regional Reliability Council and NERC on request (30 business days).</p>	<p>IV.A.M3 Standard</p> <p>IV.A.M3 Measure</p>	<p>S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.</p> <p>M3. Each transmission operator shall have on file diagrams showing the location of each blackstart generating unit that is part of the Regional blackstart capability plan (Standard IV.A. S1, M1). The diagrams shall be reviewed and updated annually or when system changes occur. Where applicable, primary and secondary cranking paths associated with each blackstart generating unit and the units to be restarted shall be identified on the diagrams. The current diagrams shall be provided to the Region and NERC on request (30 business days).</p> <p>Several transmission operators or the entire Region</p>	

<sup>2</sup> Several transmission operators or the entire Region may elect to jointly develop the diagrams to improve coordination.

Page 8 of 11

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
			may elect to jointly develop the diagrams to improve coordination.	
Section 3 Measures	M3-1. The Transmission Operator shall have evidence it provided the diagrams specified in Reliability Standard 070-R3-1 as specified in Reliability Standard 070-R3-2.	IV.A.M3 Items to be Measured	Diagram of the number, size, and location of system blackstart generating units and the initial transmission switching requirements.	
Section 3 Regional Differences	None identified.		None identified.	
Section 3 Compliance Monitoring Process	Update of diagrams showing blackstart generating units: annually or when system changes occur Current diagrams: on request (30 business days).  Regional Reliability Council	IV.A.M3 Timeframe  Compliance Monitoring Responsibility	Update of diagrams showing blackstart generating units: annually or when system changes occur. Current diagrams: on request (30 business days).  Region	
Section 3 Levels of Non Compliance	Level 1 — N/A  Level 2 — N/A  Level 3 — N/A  Level 4 — The Transmission Operator’s diagrams of the number, size, and location of system blackstart generating units and the initial transmission switching requirements were not provided, or the diagrams were not compliant with the Regional Reliability Council’s restoration plan.	IV.A.M3 Levels of Non-Compliance	Level 1 — N/A  Level 2 — N/A  Level 3 — N/A  Level 4 — The transmission operator’s diagrams of the number, size, and location of system blackstart generating units and the initial transmission switching requirements were not provided, or the diagrams were not compliant with the Regional restoration plan.	
Section 4	Documentation of blackstart generating unit test results.	Brief Description	Documentation of blackstart generating unit test results.	
Section 4	Generator Owner or Generator Operator	IV.A.M4	Generator Owners or Operators	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Applicability		Applicable to		
Section 4 Requirements	<p>R4-1. The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the blackstart capability plan as required in the regional Blackstart Plan (Reliability Standard 070-R1-1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met regional Blackstart Plan requirements.</p> <p>R4-2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Councils and upon request to NERC.</p>	<p>IV.A.M4 Standard</p> <p>IV.A.M4 Measure</p>	<p>S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.</p> <p>M4. The blackstart generating unit owner or operator shall test the startup and operation of each system blackstart generating unit identified in the blackstart capability plan as required in the regional Blackstart Plan (Standard IV.A. S1, M1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met regional Blackstart Plan requirements. A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Region in accordance with the regional Blackstart Plan or that unit will no longer be considered blackstart.</p> <p>Documentation of the test results of the startup and operation of each blackstart generating unit shall be provided to the Region and upon request to NERC.</p>	Last two sentences of M4 have been moved to a footnote to Requirement R1-1.
Section 4 Measures	M4-1. The Generator Operator shall have evidence it provided the test results specified in Reliability Standard 070-R4-1 as specified in Reliability Standard 070-R4-2.	IV.A.M4 Items to be Measured	Test results of the startup and operation of blackstart generating units.	
Section 4 Regional Differences	None identified.		None identified.	
Section 4	Current test results: to the Regional Reliability Council and	IV.A.M4	Current test results: to the Region and upon request to	Added “business” days

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Compliance Monitoring Process	upon request to NERC (30 days)  Regional Reliability Council.	Timeframe  Compliance Monitoring Responsibility	NERC (30 days).  Region	
Section 4 Levels of Non Compliance	Level 1 - Startup and operation testing of each blackstart generating unit was performed, but the documentation was incomplete.  Level 2 - Not applicable.  Level 3 -- Startup and operation testing of a blackstart generating unit was only partially performed.  Level 4 - Startup and operation testing of each blackstart generating unit was not performed	IV.A.M4 Levels of Non-Compliance	Level 1 - Startup and operation testing of each blackstart generating unit was performed but documentation was incomplete.  Level 2 - Not applicable.  Level 3 - Startup and operation testing of blackstart generating unit was only partially performed.  Level 4 - Startup and operation testing of each blackstart generating unit was not performed	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	071	Compliance Templates IV.B. M1 IV.B. M2 IV.B. M3 IV.B. M4	IV. System Restoration  B. Automatic Restoration of Load	
Title	Automatic Restoration of Load	Section:	IV. System Restoration  B. Automatic Restoration of Load	
Purpose	To ensure that automatic load restoration programs are designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.		S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.	Purpose was paraphrased from the second sentence of Standard S1
Effective Date	February 8, 2005	Approval Dates	IV.B.M1-M4 Approved for field testing in Phase III October 9, 2000	
Standard Applicability	Section 1 - Regional Reliability Council  Section 2 – Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs  Section 3 - Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs	Applicable to IV.B. M1 IV.B. M2       IV.B. M3	Section 1 – Regions Section 2 - Entities owning or operating automatic load restoration programs       Section 3 - Entities owning or operating automatic load restoration programs	Used Functional Model defined term Responsible Entity as defined for each section under Applicability

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Section 4 - Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs	IV.B. M4	Section 4 - Entities owning or operating automatic load restoration programs	
Section 1	Documentation of Regional load restoration policies and programs.	IV.B.M1 Brief Description	Documentation of Regional load restoration policies and programs.	
Section 1 Applicability	Regional Reliability Council	IV.B.M1 Applicable to	Regions	
Section 1 Requirements	<p>R1-1. A Regional Reliability Council that has a member with an automatic load restoration system shall have a documented load restoration policy and program which includes:</p> <p>a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Regional Reliability Council and, where appropriate, among Regional Reliability</p>	<p>IV.B.M1 Standard</p> <p>IV.B.M1 Measure</p>	<p>S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.</p> <p>M1. A Region that has a member with an automatic load restoration system shall have a documented load restoration policy and program which include:</p> <p>a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Region and, where appropriate, among Regions.</p> <p>b. Automatic load restoration design details</p>	Existing Standard S1 is covered in Requirement R2-1 in this section and by Requirement 3-1 in Section 3.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Councils.</p> <p>b. Automatic load restoration design details including acceptable size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays).</p> <p>c. Requirements for entities owning and operating automatic load restoration systems to provide on an annual basis current data for a Regional Reliability Council database to allow modeling the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.</p> <p>d. The maintenance and annual update of an automatic load restoration program database. This database shall include information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.</p> <p>R1-2. The Regional Reliability Council’s policies and programs shall conform with applicable NERC Standards and shall require programs to be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.</p>		<p>including acceptable size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays).</p> <p>c. Requirements for entities owning and operating automatic load restoration systems to provide on an annual basis current data for a Regional database to allow modeling the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.</p> <p>d. The maintenance and annual update of an automatic load restoration program database. This database shall include information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.</p> <p>The Regional policies and programs shall conform with applicable NERC Standards and shall require programs to be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	R1-3. The Regional Reliability Council shall provide documentation of its load restoration policy and program and a current Regional Reliability Council load restoration database to other Regional Reliability Councils and NERC within five business days of a request.		Documentation of the Regional load restoration policy and program and a current Regional load restoration database shall be provided to other Regions and NERC on request (five business days).	
Section 1 Measures	M1-1. The Regional Reliability Council has a load restoration policy and program that meets the requirements of Reliability Standard 071-R1-1 and Standard 071-R1-2 and shall have evidence the program has been provided as specified in Reliability Standard 071-R1-3.	IV.B.M1 Items to be Measured	Documentation of Regional load restoration policy and program, and an updated Regional load restoration database.	
Section 1 Regional Differences	None identified		None identified	
Section 1 Compliance Monitoring Process	Updated Regional load restoration database: annually.  Documentation of Regional policy and current database: on request (five business days).  NERC	IV.B.M1 Timeframe  Compliance Monitoring Responsibility	Updated Regional load restoration database: annually.  Documentation of Regional policy and current database: on request (five business days).  NERC	
Section 1 Levels of Non Compliance	Level 1 — Documentation of the Regional Reliability Council’s load restoration policy and program was provided, but the Regional Reliability Council’s load restoration database was not updated (Reliability Standard 071-R1-1 number 4).  Level 2 — N/A		Level 1 — Documentation of the Regional load restoration policy and program was provided, but the Regional load restoration database was not updated.  Level 2 — N/A	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Level 3 — Documentation of the Regional Reliability Council’s load restoration policy and program was provided, but was incomplete in one or more elements in Reliability Standard 071-R1-1 and Standard 071-R1-2 as defined above in Reliability Standard 071-M1-1.</p> <p>Level 4 — Documentation of the Regional Reliability Council’s load restoration policy and program was not provided.</p>		<p>Level 3 — Documentation of the Regional load restoration policy and program was provided, but was incomplete in one or more elements as defined above in Measurement M1.</p> <p>Level 4 — Documentation of the Regional load restoration policy and program was not provided.</p>	
Section 2	Documentation of automatic load restoration programs.	IV.B.M2 Brief Description	Documentation of automatic load restoration programs.	
Section 2 Applicability	Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs.	IV.B.M2 Applicable to	Entities owning or operating automatic load restoration programs	
Section 2 Requirements	<p>R2-1. The Responsible Entity shall have a policy and programs and documentation that demonstrates conformance with the Regional Reliability Council’s load restoration policy and program requirements in Reliability Standard 071-R1-1 and 071-R1-2.</p> <p>R2-2. The Responsible Entity’s documentation of its policy and program and its conformance to the Regional Reliability Council’s load restoration policy and program shall be provided to the Regional Reliability Council and NERC within five business days of a request.</p>	IV.B.M2 Measure	<p>M2. Regional members owning or operating an automatic load restoration system shall have a policy, and programs and documentation that demonstrate conformance with the Regional load restoration policy and program of Measurement IV.B. S1, M1.</p> <p>Documentation of each Regional member’s policy and program and its conformance to the Regional load restoration policy and program shall be provided to the Region and NERC on request (five business days).</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Section 2 Measure	M2-1. The Responsible Entity shall provide documentation that its load restoration policy and program meets Reliability Standard 071-R2-1 and shall have evidence the documentation was provided as specified in Reliability Standard 071-R2-2.	IV.B.M2 Items to be Measured	Documentation of Regional member’s load restoration policy and programs and their conformance with the Regional load restoration policy and program as defined in IV.B. S1, M1, including coordination and data requirements.	
Section 2 Regional Differences	None identified		None identified	
Section 2 Compliance Monitoring Process	On request (five business days).  Regional Reliability Council	IV.A.M2 Timeframe  Compliance Monitoring Responsibility	On request (five business days).  Regions	
Section 2 Levels of Non Compliance	Level 1 — Documentation of the Responsible Entity’s automatic load restoration policy and programs was provided, but the required data was not current.  Level 2 — Documentation of the Responsible Entity’s automatic load restoration policy and programs was provided, but coordination as required in the Regional Reliability Council’s policy and program (Reliability Standard 071-R1-1 elements a-d) was not provided or was incomplete  Level 3 — Documentation of the Responsible Entity’s automatic load restoration policy and programs was provided, but was incomplete in one of the areas required by the Regional Reliability Council’s load restoration policy and program (Reliability Standard 071-R1-1 elements a-d).	IV.B.M2 Levels of Non-Compliance	Level 1 — Documentation of the Regional member’s automatic load restoration policy and programs was provided, but the required data was not current.  Level 2 — Documentation of the Regional member’s automatic load restoration policy and programs was provided, but coordination as required in the Regional policy and program (IV.B. S1, M1) was not provided or was incomplete.  Level 3 — Documentation of the Regional member’s automatic load restoration policy and programs was provided, but was incomplete in one of the areas required by the Regional load restoration policy and program (IV.B. S1, M1).	Added references to the specific elements requirements being addressed.  Added references to the specific elements of the requirements being addressed.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Level 4 — Documentation of the Responsible Entity’s automatic load restoration policy and programs was not provided, or was provided but was missing two or more areas required by the Regional Reliability Council’s load restoration policy and program (Standard 071-R1-1 elements a-d), or does not conform with the Regional Reliability Council’s load restoration policy and program (Standard 071-R1-2).		Level 4 — Documentation of the Regional member’s automatic load restoration policy and programs was not provided, or was provided but was missing two or more areas required by the Regional load restoration policy and program, or does not conform with the Regional load restoration policy and program (IV.B. S1, M1).	Added references to the specific elements requirements being addressed.
Section 3	Assessment of the effectiveness of automatic load restoration programs.	IV.B.M3 Brief Description	Assessment of the effectiveness of automatic load restoration programs.	
Section 3 Applicability	Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs.	IV.B.M3 Applicable to	Entities owning or operating automatic load restoration programs	
Section 3 Requirements	<p>R3-1. The Responsible Entity shall demonstrate through simulation that the design and implementation of its programs do not cause electric system underfrequencies or undervoltages, the overloading of transmission facilities, or delay in the restoration of facilities and interconnection tie lines to neighboring systems.</p> <p>R3-2. The Responsible Entity shall make its documentation of the results of the simulation of the automatic load restoration programs available to the appropriate (affected) Regional Reliability Councils and NERC</p>	IV.B.M3 Measure	<p>M3. Those entities owning or operating an automatic load restoration program shall demonstrate through simulation that the design and implementation of their programs do not cause electric system underfrequencies or undervoltages, the overloading of transmission facilities, or delay in the restoration of facilities and interconnection tie lines to neighboring systems.</p> <p>Documentation of the results of the simulation of the automatic load restoration programs shall be available to the appropriate (affected) Regions and NERC on request (30 business days).</p>	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	within 30 business days of a request.			
Section 3 Measures	M3-1. The Responsible Entity shall provide documentation that simulations demonstrate that the design and implementation of the automatic load restoration programs meets Reliability Standard 071-R3-1 and shall have evidence the documentation was made available as specified in Reliability Standard 071-R3-2.	IV.B.M3 Items to be Measured	Documentation of the simulations demonstrating that the design and implementation of the automatic load restoration programs do not cause the system impacts as described in above Measurement M3.	
Section 3 Regional Differences	None identified		None identified	
Section 3 Compliance Monitoring Process	On request (30 business days).  Regional Reliability Councils	IV.A.M3 Timeframe  Compliance Monitoring Responsibility	On request (30 business days).  Regions	
Section 3 Levels of Non Compliance	Level 1 — N/A  Level 2 — N/A  Level 3 — N/A  Level 4 — Documentation of the simulations of the design and implementation of the Responsible Entity’s automatic load restoration program was not provided, or the automatic load restoration program was not operated in conformance with the Regional Reliability Council’s load restoration policy and program (Reliability Standard 071-R1-1 and Standard 071-R1-2) or the requirements of	IV.B.M3 Levels of Non-Compliance	Level 1 — N/A  Level 2 — N/A  Level 3 — N/A  Level 4 — Documentation of the simulations of the design and implementation of the entity’s automatic load restoration program was not provided, or the entity’s automatic load restoration program was not operated in conformance with the Region’s load restoration policy and program or the requirements of the above Measurement M3.	



Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	Reliability Standard 071-R3-1.			
Section 4	Automatic load restoration equipment maintenance requirements.	IV.B.M4 Brief Description	Automatic load restoration equipment maintenance requirements.	
Section 4 Applicability	Responsible Entity may be any of the following: Transmission Owner, Transmission Operator, Distribution Provider, or Load Serving Entity owning or operating automatic load restoration programs	IV.B.M4 Applicable to	Entities owning or operating automatic load restoration programs	
Section 4 Requirements	<p>R4-1. The Responsible Entity shall document and implement a maintenance program that ensures accurate and reliable operation of the automatic load restoration relays.</p> <p>R4-2. The Responsible Entity shall provide its documentation of the implementation of the maintenance program to the appropriate (affected) Regional Reliability Councils and NERC within 30 business days of a request.</p>	IV.B.M4 Measure	<p>M4. Those entities owning or operating automatic load restoration programs shall document and implement a maintenance program that ensures accurate and reliable operation of the automatic load restoration relays.</p> <p>Documentation of the implementation of the maintenance program shall be provided to the appropriate (affected) Regions and NERC on request (30 business days).</p>	
Section 4 Measures	M4-1. The Responsible Entity's documentation of its implementation of the maintenance program includes all elements identified in Reliability Standard 071-R4-1 and the Responsible Entity has evidence that it provided this documentation as specified in Reliability Standard 071-R4-2.	IV.B.M4 Items to be Measured	Documentation of the maintenance program and its implementation.	
Section 4 Regional Differences	None identified		None identified	
Section 4 Compliance Monitoring	On request (30 business days).	IV.A.M4 Timeframe	On request (30 business days).	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Process	Regions	Compliance Monitoring Responsibility	Regions	
Section 4 Levels of Non Compliance	Level 1 -   The Responsible Entity’s documentation of the implementation of the automatic load restoration maintenance program was complete, but the maintenance program documentation was incomplete.	IV.B.M4 Levels of Non-Compliance	Level 1 -   Documentation of the implementation of the automatic load restoration maintenance program was complete, but the maintenance program documentation was incomplete.	Version 1 needs to address better levels of non-compliance
	Level 2 -   Not applicable.		Level 2 -   Not applicable.	
	Level 3 -   The Responsible Entity’s documentation of the maintenance program and its implementation for the automatic load restoration system was not available, but maintenance is being performed.		Level 3 -   Documentation of the maintenance program and its implementation for the automatic load restoration system was not available, but maintenance is being performed.	
	Level 4 -   The Responsible Entity’s documentation of the maintenance program and its implementation for the automatic load restoration system was not available, and maintenance was not being performed.		Level 4 -   Documentation of the maintenance program and its implementation for the automatic load restoration system was not available, and maintenance was not being performed.	

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
Standard	072	(No Number Exists)	Vegetation Management Program	The Vegetation Management Program standard was introduced with the revised standards produced by the CTF and approved by the NERC Board of Trustees on April 2, 2004. It was not given a number in the format of the original Planning Standards.
Title	Vegetation Management Program	(No Number Exists)	Vegetation Management Program	
Purpose	To ensure that transmission owners have a vegetation management program to prevent transmission line contact with vegetation, and to ensure that certain vegetation-related outages are reported to the appropriate	(No Purpose Exists)	None.	Language paraphrased from the Requirements of the Standard. See below, Section 1.
Effective Date	February 8, 2005	Approved by NERC BOT	April 2, 2004	
Standard Applicability	Transmission Owners	Applicable to	Transmission Owners.	
Section 1	Vegetation Management program for Transmission Owner	Brief Description	Vegetation Management program for Transmission Owners	
Section 1 Applicability	Transmission Owners	Applicable to	Transmission Owners	Same as “Applicable To,” above
Section 1 Requirements	<p>R1-1. Each transmission owner shall have a vegetation management program to prevent transmission line contact with vegetation. The vegetation management program shall include the following three elements:</p> <ol style="list-style-type: none"> <li>1. Inspection requirements</li> <li>2. Trimming clearances</li> <li>3. Annual work plan</li> </ol>	Requirements	<p>1. Each transmission owner shall have a vegetation management program to prevent transmission line contact with vegetation. The vegetation management program shall include the following elements:</p> <ul style="list-style-type: none"> <li>• Inspection requirements</li> <li>• Trimming clearances</li> <li>• Annual work plan</li> </ul>	Clarified the three sub-requirements of Requirement One by converting bullets to numbers.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	R1-2. Each Transmission Owner shall report to its Regional Reliability Council all vegetation-related outages on transmission circuits 200 kV and higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system.		2. Each transmission owner shall report to its Regional Reliability Council all vegetation-related outages on transmission circuits 200 kV and higher and any other lower voltage lines designated by the RRC to be critical to the reliability of the electric system.	
Section 1 Measures	<p>M1-1. The Transmission Owner’s vegetation management program documentation contains the following elements:</p> <ol style="list-style-type: none"> <li>1. Inspection requirements</li> <li>2. Trimming clearances</li> <li>3. Annual work plan</li> </ol> <p>M1-2. The Transmission Owner shall have evidence it performs vegetation program maintenance in the annual work plan according to the requirements and procedures contained in the program.</p> <p>M1-3. The Transmission Owner shall have evidence it reported all vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system</p>	Items to be Measured	<p>1. The vegetation management program documentation contains the following elements:</p> <p>Inspection requirements Trimming clearances Annual work plan</p> <p>2. The transmission owner performs vegetation program maintenance in the annual work plan according to the requirements and procedures contained in the program.</p> <p>3. All vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system are reported.</p>	Clarified the three sub-measurements of Measurement One by converting bullets to numbers.
Section 1 Regional Differences	None identified.		None identified.	
Section 1 Compliance Monitoring Process	<p><b><u>Reporting Requirements</u></b></p> <p><b>Self-certification</b></p> <p>The Transmission Owner annually self-certifies that it has performed vegetation program maintenance in the annual work plan according to</p>	Reporting Requirements	<p><b><u>Reporting Requirements</u></b></p> <p><b>Self-certification</b></p> <p>The transmission owner annually self-certifies that it has performed vegetation program maintenance in the annual work plan according</p>	The Vegetation Management Program standard contained a significant amount of information not captured in the other existing Planning Standards. All of this extra information best fit into the

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>the requirements and procedures contained in the program.</p> <p><b>Periodic Reporting</b></p> <p>Transmission Owners shall report vegetation-related line outages on transmission circuits 200 kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system, to the Region for a calendar month by the 20th of the following month. The Region shall report quarterly results to NERC.</p> <p>All outages shall be reported where the cause of the outage is the line faulting due to contact with vegetation, except:</p> <ul style="list-style-type: none"><li>• Multiple outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.</li><li>• A single trip followed by a successful automatic reclose within a 24-hour period shall not be a reportable outage.</li></ul> <p><b><u>Reporting Period</u></b></p> <p><b>Three-year Audit</b></p> <p>The Compliance Monitor will conduct an on-site review every three years. The Vegetation Management Program will be reviewed and assessed.</p> <p><b>Self-Certification</b></p> <p>The Transmission Owner annually submits a self-certification that it has performed all vegetation management maintenance in the annual work plan during the past calendar year that is described in the Vegetation</p>	Reporting Period	<p>to the requirements and procedures contained in the program.</p> <p><b>Periodic Reporting</b></p> <p>Transmission owners shall report vegetation-related line outages on transmission circuits 200 kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system, to the Region for a calendar month by the 20th of the following month. The Region shall report quarterly results to NERC.</p> <p>All outages shall be reported where the cause of the outage is the line faulting due to contact with vegetation, except:</p> <ul style="list-style-type: none"><li>• Multiple outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.</li><li>• A single trip followed by a successful automatic reclose within a 24-hour period shall not be a reportable outage.</li></ul> <p><b><u>Reporting Period</u></b></p> <p><b>Three-year Audit</b></p> <p>The Compliance Monitor will conduct an on-site review every three years. The Vegetation Management Program will be reviewed and assessed.</p> <p><b>Self-Certification</b></p> <p>The Transmission Owner annually submits a self-certification that it has performed all vegetation management maintenance in the annual work plan during the past calendar year that is described in</p>	Compliance Monitoring Process section of the new standard.

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>Management Program.</p> <p><b>Periodic Reporting</b></p> <p>All vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system will be reported to the region on a monthly basis by the 20th of the following month. The Region shall report quarterly results to NERC by the last business day of January, April, July, and October.</p> <p><b><u>Compliance Reset Period</u></b> One calendar quarter</p> <p><b><u>Compliance Monitoring Responsibility</u></b> Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>	<p>Compliance Reset Period</p> <p>Compliance Monitoring Responsibility</p>	<p>the Vegetation Management Program.</p> <p><b>Periodic Reporting</b></p> <p>All vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system will be reported to the region on a monthly basis by the 20th of the following month. The Region shall report quarterly results to NERC by the last business day of January, April, July, and October.</p> <p><b><u>Compliance Reset Period</u></b> One calendar quarter</p> <p><b><u>Compliance Monitoring Responsibility</u></b> Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.</p>	
Section 1 Levels of Non Compliance	<p>The Transmission Owner is in Full Compliance if the following Requirements are met:</p> <p><b>Three-year Audit</b> The vegetation management program is fully documented and contains all three elements listed in Measurement M1-1of this Reliability Standard.</p> <p><b>Self-Certification</b> The transmission owner performed all maintenance as described in the annual work plan.</p> <p><b>Periodic Reporting</b> All vegetation-related transmission line outages of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of</p>	Full Compliance Requirements	<p><b>Three-year Audit</b> The vegetation management program is fully documented and contains all three elements listed in Requirement 1 of items to be measured.</p> <p><b>Self-Certification</b> The transmission owner performed all maintenance as described in the annual work plan.</p> <p><b>Periodic Reporting</b> All vegetation-related transmission line outages of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system are reported during a calendar quarter.</p>	<p>“Levels of Non-Compliance” were not specified in the current Standard. The current Standard only identified Compliant or Non-Compliant.</p>

Draft Version 0 Standard Language		Source Document		
Heading	New Language	Heading	Existing Document Language	Comments
	<p>the electric system are reported during a calendar quarter.</p> <p>The transmission owner is non-compliant if:</p> <ul style="list-style-type: none"><li>• Vegetation-related outages occurred and were not reported during a one-month period</li><li>• The Vegetation Management Plan is found to be not complete</li><li>• The transmission owner did not perform necessary maintenance described in the annual work plan as reported via self-certification.</li></ul>	Non-Compliance	<p>The transmission owner is non-compliant if:</p> <ul style="list-style-type: none"><li>• Vegetation-related outages occurred and were not reported during a one-month period</li><li>• The Vegetation Management Plan is found to be not complete</li><li>• The transmission owner did not perform necessary maintenance described in the annual work plan as reported via self-certification.</li></ul>	



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@aol.com](mailto:naesb@aol.com)

Home Page: [www.naesb.org](http://www.naesb.org)

**via email and posting**

**TO:** NAESB WEQ Business Practices Subcommittee Participants  
**FROM:** Rae McQuade, Executive Director  
**RE:** Request for Standards Development and Timeline and Deliverable Dates for Preparing "Version 0" Business Practices  
**DATE:** May 13, 2004

Dear WEQ BPS Interested Parties,

The WEQ BPS met on May 11 to discuss the transition of the business practices in the existing NERC policies from those NERC policies to NAESB business practices. The goal of the meeting was twofold – to finalize the request for standards development, and to set a timeline and deliverables deadlines that coincide with NERC's Transition Plan for developing "Version 0" reliability standards.<sup>1</sup> The request was unanimously endorsed by the BPS on May 11 and is attached for your information. The timeline also attached, was drafted by the NAESB office with the BPS leadership in coordination with NERC and the ISO RTO Council.

Please note that the intent of the request is to develop "Version 0" business practices that complement the "Version 0" reliability standards. "Version 0" reflects the business practices from the reliability operating policies, planning standards and compliance templates in effect today, with language changes for consistency with the NERC functional model.

Best Regards,

*Rae McQuade*

Rae McQuade

Executive Director, North American Energy Standards Board

cc: WEQ Executive Committee Members  
 Mark Fidrych  
 Glenn Ross  
 Mike Grim  
 Linda Campbell  
 Gerry Cauley  
 Bill Lohrman  
 Don Benjamin

Gordon Scott  
 Michael Desselle  
 Lou Oberski  
 Steve Cobb  
 Phil Cox  
 Joel Dison  
 DeDe Kirby  
 Todd Oncken

<sup>1</sup> The NERC Accelerated Transition Plan can be downloaded from:

[http://www.nerc.com/pub/sys/all\\_updl/standards/Accelerated-Standards-Transition-Plan-Draft-4-19-04-FINAL.pdf](http://www.nerc.com/pub/sys/all_updl/standards/Accelerated-Standards-Transition-Plan-Draft-4-19-04-FINAL.pdf)





## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@aol.com](mailto:naesb@aol.com)

Home Page: [www.naesb.org](http://www.naesb.org)

---

***WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING  
SCHEDULE OF EVENTS AND MILESTONES TO PREPARE "VERSION 0" BUSINESS PRACTICES  
PLAN UPDATED JUNE 14, 2004***

<b>Date</b>	<b>Time</b>	<b>Location</b>	<b>Event</b>
May 11	1 – 4 P Central	Houston	NAESB WEQ BPS Meeting
May 20- 21	All Day	Chicago	NERC Standards Drafting Team Meeting
June 2-3	2 <sup>nd</sup> 10 A – 5 P 3 <sup>rd</sup> 9 A – 3 P Eastern	Atlanta	NAESB WEQ BPS Meeting
June 9- 11	All Day	Chicago	NERC Standards Drafting Team Meeting
June 17- 18	All Day	Columbus, OH	NAESB WEQ BPS Meeting
June 28- 30	All Day	Chicago	NERC Standards Drafting Team Meeting
July 2			Distribution of NERC Version 0 Reliability Standards Draft 1 for comment
July 7 – 8	All Day	Houston	NAESB WEQ BPS Meeting
July 9			Distribution of NAESB Version 0 Business Practice Standards Draft 1 for comment – comments to be returned by August 9
July 16	11 A – 3 P	Tampa, FL	Proposed JIC Meeting where the two version 0 requests (the SAR from NERC and the request from NAESB) will be presented for JIC review and assignment – presumably to NERC and NAESB.
Aug 9			Comments returned to NAESB on proposed standards included in Draft 1 of the NAESB Version 0 Business Practice Standards
Aug 11- 13	All Day	??	NERC Standards Drafting Team Meeting
Aug 17- 18	All Day	Houston	NAESB WEQ BPS Meeting
Aug 24	All Day	Colorado Springs	NAESB WEQ EC Meeting
Aug 30			Distribution of NERC Version 0 Reliability Standards Draft 2 for comment
Aug 30			Distribution of NAESB Version 0 Business Practice Standards Draft 2 for comment – comments to be returned



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@aol.com](mailto:naesb@aol.com)

Home Page: [www.naesb.org](http://www.naesb.org)

---

***WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING  
SCHEDULE OF EVENTS AND MILESTONES TO PREPARE "VERSION 0" BUSINESS PRACTICES  
PLAN UPDATED JUNE 14, 2004***

<b>Date</b>	<b>Time</b>	<b>Location</b>	<b>Event</b>
			by September 30
Sep 30			Comments returned to NAESB on proposed standards included in Draft 2 of the NAESB Version 0 Business Practice Standards
Oct 12-13	All Day	Washington DC	NAESB WEQ BPS Meeting
Oct 25			Distribution of NERC Version 0 Reliability Standards Draft 3 for comment
Oct 25			Distribution of NAESB Version 0 Business Practice Standards Draft 3 for comment – comments to be returned by November 25
Nov 16	All Day	Washington DC	NAESB WEQ EC Meeting
Nov 25			Comments returned to NAESB on proposed standards included in Draft 3 of the NAESB Version 0 Business Practice Standards. Comments forwarded to the WEQ EC for consideration with Draft 3 for vote.
Nov 30	All Day	Tampa	WEQ EC Meeting, EC vote on proposed standards included in Draft 3 proposed standards including consideration of comments submitted on November 25.
Nov 30			Assuming the proposed standards are adopted by the EC on November 30, the EC-endorsed proposed standards are sent out to the WEQ membership for ratification.
Dec 30			Ratification ballot due back to the NAESB office. Assuming results indicate that members ratify EC-endorsed proposed standards, they are considered NAESB standards.

**R04013**  
**North American Energy Standards Board**

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

**Date of Request:** May 13 2004

**1. Submitting Entity & Address:**

WEQ Business Practices Subcommittee

**2. Contact Persons, Phone #, Fax #, Electronic Mailing Address:**

<b>Name :</b>	Phil Cox	Mr. Joel Dison
<b>Company:</b>	American Electric Power	Southern Company
<b>Title :</b>	Transmission and Markets Analyst	Manager of Market Policy
<b>Phone:</b>	614-324-4598	(205) 257-6481
<b>Fax :</b>	614-583-7505	(205) 257-6824
<b>E-mail :</b>	epcox@aep.com	jjdison@southernco.com

**3. Description of Proposed Standard or Enhancement:**

Prepare business practices that support NERC's reliability practices and functional model terminology reflective of today's implementation. This request should be considered a companion request to the NERC Standards Authorization Request for Version 0 Reliability Standards.

The NERC Board of Trustee-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 balloted in April 2004 – will be translated into an initial baseline (Version 0) set of business practice standards. The list of items can be found as an attachment – see item 10 of this request.

As NERC notes in its SAR:

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

a The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

b The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."

c An April 14, 2004 Order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."

d The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.

e The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

NERC's reliability policies have essential business practice elements that integrally support the reliability standards. However, from NAESB's perspective, such business practice standards when adopted would be voluntary. Regulatory agencies may then take their own subsequent actions to make such standards jurisdictionally enforceable. NAESB will coordinate its filing with the FERC to coincide with NERC adoption of the Version 0 standards.

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

These business practice standards will be drafted to implement existing business practices as they reside in NERC's current reliability operating policies and planning standards effective today:

- a. Extract the business practices from the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 balloted in April 2004 – into an initial baseline (Version 0) set of business practice standards.
- b. Follow NERC's effort to identify the Functional Model designation for each performance requirement and measure in the Version 0 standards, and reflect the same functional model terminology in NAESB business practices.
- c. Work collaboratively with NERC to identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into NAESB "Version 0" business practice standards.

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

As described above, these complementary business practice standards are integral to the operation and enforceability of NERC's reliability standards. The collaborative effort with NERC to prepare a Version 0 foundation of business practices will serve as a cornerstone for future NAESB business practice standards development.

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

There should be no additional costs to implement the business practices supporting Version 0 reliability standards as these business practices are in effect today in NERC's operating policies and planning standards.

**7. Description of Any Specific Legal or Other Considerations:**

NAESB should continue to coordinate with NERC as the Version 0 business practices are developed to ensure that they fully support and track NERC's reliability standards.

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

There should be no additional testing required to implement the business practices supporting Version 0 reliability standards as these business practices are in effect in current NERC operating policies and planning standards today.

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

Please see the response to item 8.

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

NERC operating policies, planning standards, and compliance templates

<http://www.nerc.com/~oc/pds.html> (operating policies)

<http://www.nerc.com/~oc/standards/> (revised operating policy 5, 6, 9)

<http://www.nerc.com/~filez/pss-psg.html> (planning standards)

<http://www.nerc.com/~comply/annual.html> (compliance templates)

Functional model

<http://www.nerc.com/~filez/functionalmode1.html>

NERC Transition Plan

[ftp://www.nerc.com/pub/sys/all\\_updl/standards/Accelerated-Standards-Transition-Plan-Draft-4-19-04-FINAL.pdf](ftp://www.nerc.com/pub/sys/all_updl/standards/Accelerated-Standards-Transition-Plan-Draft-4-19-04-FINAL.pdf)

SAR – Version 0 reliability standards development

<http://www.nerc.com/~filez/standards/Version-0.html>



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
 Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
 Home Page: [www.naesb.org](http://www.naesb.org)

**via email and posting**

**TO:** NAESB Wholesale Electric Quadrant Business Practices Subcommittee  
**FROM:** Rae McQuade, NAESB Executive Director  
**cc:** DeDe Kirby, NAESB Office  
 Joel Dison and Phil Cox, NAESB BPS Co-chairs  
**RE:** Request for Comments Regarding First Draft of Version 0 NAESB Business Practices  
**DATE:** July 9, 2004

Dear WEQ BPS participants, WEQ Members and Interested Parties,

The North American Energy Standards Board's (NAESB) Wholesale Electric Quadrant (WEQ) Business Practices Subcommittee (BPS) solicits industry comments on the first draft of its Version 0 Business Practice Standards. Please forward any comments you have by August 9 to the NAESB Office ([naesb@naesb.org](mailto:naesb@naesb.org), fax: 713-356-0067). If you have any questions regarding the comment process please contact DeDe Kirby at our office (713-356-0060, [dkirby@naesb.org](mailto:dkirby@naesb.org)). Your comments will be attributed and posted on the NAESB web site as they are received.

These proposed standards are being developed in conjunction with efforts by the North American Electric Reliability Counsel (NERC) to convert its policies into stand-alone Reliability Standards. The BPS, in conjunction with several NERC committees and subcommittees, have identified certain business practices contained within the NERC policies which should be developed as Business Practice Standards instead of Reliability Standards. This process is described in the attached Action Plan.

The purpose of this solicitation is to not only provide an update to the industry on the progress of that effort but also to seek comment on the direction being taken by that effort. Comments on the direction we are taking, the proposed standards, and answers to questions below shall be returned to the NAESB Office by August 9, 2004.

All proposed standards and supporting documentation can be found on the NAESB web site at the following address: [http://www.naesb.org/weq/weq\\_bps\\_doc.asp](http://www.naesb.org/weq/weq_bps_doc.asp).

In developing these business practice standards, the NAESB WEQ BPS took a very similar approach as that being taken by the NERC Version 0 Drafting Team. That approach can be summarized as follows:

1. There would be no change to the intent of the original provisions in the NERC policy.
2. The language would be converted into "standards language", replacing passive language with more active directives and requirements that clearly indicate the entity responsible for the action.
3. The standards would be written in accordance with the NERC Functional Model, replacing references such as "control area" and "system operator" with the appropriate Functional Model reference such as "Balancing Authority", "Transmission Operator", etc. However, NERC has decided that the "Interchange Authority" will not be implemented as part of the NERC Version 0 Reliability Standards. Consequently, NAESB will likewise not include "Interchange Authority" in any NAESB Version 0 Business Practice Standard.



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)

Home Page: [www.naesb.org](http://www.naesb.org)

---

Generally speaking, where business practices were clearly identified, and it was agreed that NAESB should develop standards associated with those practices, the NERC Version 0 drafting team eliminated those practices from the conversion of the policy into reliability standards. In some cases, however, it should be pointed out that it was not possible and/or entirely practicable to completely eliminate the presence of the business practice in the NERC Version 0 Reliability Standard development. In these situations, the business practice standard and the reliability standard may contain very similar language, but will do so for very different purposes, namely defining the business and reliability requirements, respectively. The NAESB WEQ BPS has referred to this as the creation of “shadow” business practices, although in reality it is actually the planned transition of commercial issues out of reliability standards into business practice standards. It is fully expected that future versions of the NAESB Business Practice standards will expand upon these foundational “shadow” requirements. It is also fully expected that future versions of the NERC Reliability Standards will continue to de-emphasize commercial requirements, focusing instead on core reliability requirements. As such, any appearance of “duplication” should be considered temporary at worst. Until that duplication can be eliminated, extreme care has been (and will continue to be) taken to ensure no conflicts exist between the NERC requirements and the NAESB Business Practice Standards. This “shadowing” transition process is supported by both the NAESB WEQ BPS and the NERC Version 0 Drafting Team and is in complete harmony with the NERC/NAESB/IRC Memorandum of Understanding for coordination of standards development.

This posting represents the first draft of the proposed NAESB Version 0 Business Practices. It is recognized there are several outstanding issues that will be addressed in subsequent draft postings. This includes but is not limited to:

- Incorporation of the Time Error Correction Appendix A into the body of its requirements.
- Reconciliation of various document formatting inconsistencies
- Development of/or reference to an official glossary or other source of definitions for defined terms

Many of the proposed standards impose requirements on NERC Organizational Subcommittees as originally required in the NERC policies. The BPS believes that carrying those requirements forward into the NAESB Business Practice Standards is appropriate and seeks confirmation of that decision.

The following summarizes the Business Practice Standards being proposed as part of this process.

**1. Time Control.** The BPS converted NERC Policy 1, Section D, including Appendix 1D as a Business Practice Standard.

The BPS seeks industry comment on the conversion of the policy language into the proposed Business Practice Standard.

**2. Inadvertent Energy Payback.** The BPS converted NERC Policy 1, Section F, Requirements 4 (Inadvertent Payback) and 5 (Accounting) and Appendix 1F (Dispute Resolution) as a Business Practice Standard. Although the accounting provisions in Requirement 5 are primarily commercial, the NERC Version 0 drafting team determined to maintain that requirement in its reliability requirements as well to ensure metering and recording of



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

inadvertent for reliability purposes. Therefore, the accounting portion of this standard is a “shadow” requirement.

The BPS seeks industry comment on the conversion of the policy language into the proposed Business Practice Standard. Furthermore, the BPS discovered apparent inconsistencies in the reporting deadline requirements between the original policy language, appendices and the NERC training manual. The BPS seeks clarification that it has appropriately represented inadvertent reporting deadline requirements.

**3. ACE Equation Special Cases.** The BPS converted NERC Policy 1, Appendix 1A, Sections B, C, and D as a Business Practice Standard. These special cases are primarily associated with special commercial situations and therefore represent business practices for modeling those commercial situations in the ACE equation. The NERC Version 0 Drafting team has not determined whether it will (a) convert these appendices into reliability standards, (b) include these appendices into a reference document, or (c) eliminate them altogether from reliability requirements under the presumption that they will become NAESB business practice standards.

The BPS seeks industry comment on the conversion of the policy language into the proposed Business Practice Standard. It also seeks answers to these questions associated with this standard:

- (1) Should NAESB develop them as a business practice standard even if NERC eliminates them completely? If not a standard, should it be a best practice guide?
- (2) If NERC does not adopt them as part of its reliability requirements but instead incorporates them into a reference document, should NAESB develop them as a business practice standard anyway? If not a standard, should it be a best practice guide?
- (3) If NERC keeps these sections as part of its Version 0 reliability requirements, should NAESB “shadow” them as a business practice standard or best practice guide as well?

**4. Coordinate Interchange.** In April, NAESB ratified “Version 1” of its Coordinate Interchange Business Practices (CIBP) Standard, which was essentially the conversion of the business practice elements of Policy 3, including the appropriate Policy 3 appendices. For Version 0, however, NERC has chosen NOT to implement the Interchange Authority. Therefore, The “Version 1 CIBP” had to be “reverted” into a Version 0 compatible standard. In developing the NERC Version 0 coordinate interchange requirements, the NERC Version 0 drafting team decided to maintain all of the Policy 3 appendices as part of the reliability requirements. Because these appendices are integral to both the NERC Version 0 reliability requirements and the NAESB Version 0 CIBP standard, it was necessary to “shadow” those appendices in both the NERC and NAESB standards.

The BPS seeks industry comment on the development of the Version 0 CIBP, including the inclusion of the Policy 3 appendices as an integral part of that standard.

**5. Emergency Operations.** The BPS converted several key business practices that were inherent to key sections of NERC Policy 5, as approved by the NERC BOT in April 2004, as a NAESB Business Practice Standard. These business practices formed the “context” for which the reliability requirements were based and were therefore not removed from NERC Policy. However, they establish the business practices upon which certain emergency situations should be predicated and form a foundation for future business practice development in this





## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)

Home Page: [www.naesb.org](http://www.naesb.org)

---

area. Therefore, this standard represents a “shadowing” of the Business Practice that will be embedded in those NERC Version 0 Reliability Standards.

The BPS seeks industry comment on the conversion of the policy language into the proposed Business Practice Standard.

**6. Transmission Loading Relief (TLR).** The BPS converted NERC Policy 9 Appendices 9C1, 9C1B, and 9C1C into a NAESB Business Practice Standard, combining all three appendices into a single standard set. These appendices are primarily commercial in nature. The NERC Drafting Team has agreed that the TLR procedure will NOT be part of the core reliability requirements but will, instead be an attachment to those requirements. Prior to ratification of its Version 0 Standards, NERC will decide whether to retain the language contained within the original NERC appendices or incorporate this NAESB TLR Standard.

The BPS seeks industry comment on the conversion of the policy language into the proposed Business Practice Standard.

Best Regards and we look forward to receiving your comments –

*Rae McQuade*

Rae McQuade  
NAESB Executive Director



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

### Attachment A: WEQ BPS Schedule of Events

**WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING  
SCHEDULE OF EVENTS AND MILESTONES TO PREPARE "VERSION 0" BUSINESS  
PRACTICES  
PLAN UPDATED JUNE 14, 2004**

Date	Time	Location	Event
May 11	1 – 4 P Central	Houston	NAESB WEQ BPS Meeting
May 20- 21	All Day	Chicago	NERC Standards Drafting Team Meeting
June 2- 3	2 <sup>nd</sup> 10 A – 5 P 3 <sup>rd</sup> 9 A - 3 P Eastern	Atlanta	NAESB WEQ BPS Meeting
June 9- 11	All Day	Chicago	NERC Standards Drafting Team Meeting
June 17-18	All Day	Columbus, OH	NAESB WEQ BPS Meeting
June 28-30	All Day	Chicago	NERC Standards Drafting Team Meeting
July 2			Distribution of NERC Version 0 Reliability Standards Draft 1 for comment
July 7 – 8	All Day	Houston	NAESB WEQ BPS Meeting
July 9			Distribution of NAESB Version 0 Business Practice Standards Draft 1 for comment – comments to be returned by August 9
July 16	11 A – 3 P	Tampa, FL	Proposed JIC Meeting where the two version 0 requests (the SAR from NERC and the request from NAESB) will be presented for JIC review and assignment – presumably to NERC and NAESB.
Aug 9			Comments returned to NAESB on proposed standards included in Draft 1 of the NAESB Version 0 Business Practice Standards
Aug 11- 13	All Day	??	NERC Standards Drafting Team Meeting



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

**WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING  
SCHEDULE OF EVENTS AND MILESTONES TO PREPARE "VERSION 0" BUSINESS  
PRACTICES  
PLAN UPDATED JUNE 14, 2004**

Date	Time	Location	Event
Aug 17-18	All Day	Houston	NAESB WEQ BPS Meeting
Aug 24	All Day	Colorado Springs	NAESB WEQ EC Meeting
Aug 30			Distribution of NERC Version 0 Reliability Standards Draft 2 for comment
Aug 30			Distribution of NAESB Version 0 Business Practice Standards Draft 2 for comment – comments to be returned by September 30
Sep 30			Comments returned to NAESB on proposed standards included in Draft 2 of the NAESB Version 0 Business Practice Standards
Oct 12-13	All Day	Washington DC	NAESB WEQ BPS Meeting
Oct 25			Distribution of NERC Version 0 Reliability Standards Draft 3 for comment
Oct 25			Distribution of NAESB Version 0 Business Practice Standards Draft 3 for comment – comments to be returned by November 25
Nov 16	All Day	Washington DC	NAESB WEQ EC Meeting
Nov 25			Comments returned to NAESB on proposed standards included in Draft 3 of the NAESB Version 0 Business Practice Standards. Comments forwarded to the WEQ EC for consideration with Draft 3 for vote.
Nov 30	All Day	Tampa	WEQ EC Meeting, EC vote on proposed standards included in Draft 3 proposed standards including consideration of comments submitted on November 25.
Nov 30			Assuming the proposed standards are adopted by the EC on November 30, the EC-endorsed proposed standards are sent out to the WEQ membership for ratification.
Dec 30			Ratification ballot due back to the NAESB office.



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)

Home Page: [www.naesb.org](http://www.naesb.org)

---

***WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING  
SCHEDULE OF EVENTS AND MILESTONES TO PREPARE "VERSION 0" BUSINESS  
PRACTICES  
PLAN UPDATED JUNE 14, 2004***

---

<b>Date</b>	<b>Time</b>	<b>Location</b>	<b>Event</b>
			Assuming results indicate that members ratify EC-endorsed proposed standards, they are considered NAESB standards.

---



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

### **Attachment B: Version 0 Action Plan**

#### **Introduction**

The NAESB Wholesale Electric Quadrant Business Practice Subcommittee met on June 17 & 18, 2004 at the AEP Offices in Columbus, OH. The purpose of this meeting was for NAESB WEQ BPS to develop an action plan for developing business practices identified as being embedded within existing NERC Operating Policies and Planning Standards.

While presenting the NAESB proposals to the NERC Version 0 Standard Drafting Team in Chicago on June 9-11, 2004, the NERC drafting team determined that, for many of the recommendation, it was not in the best interests of the NERC Version 0 process to remove the business practices from the reliability standards development. As a result, the BPS determined that despite this decision by NERC, NAESB should proceed with developing these Version 0 business practices (including some that may be “shadow” business practices to requirements included in the NERC Version 0 reliability requirements) so as to form a foundation upon which further business practice efforts can build. A “shadow” business practice is intended to substantively match the business requirements contained within the NERC Version 0 reliability standards. It is NAESB’s expectation that these business requirements contained in the NERC Version 0 reliability standards will be removed from subsequent versions of NERC standards.

The following summarizes the original recommendation, the discussions at the NERC drafting team meeting, and the action plan for the recommendation as determined by the NAESB BPS.

#### **NERC Operating Policy 1 – “Generation Control & Performance”**

Original Recommendation:

Section D “Time Control Standard”. NAESB would adopt this section of Policy 1, as is, for inclusion in Version 0 business practices, including Appendix 1D.

Reasoning as follows:

- Correction of a deviation that either had no reliability impact or was handled via another reliability standard
- No reliability purpose for the correction, commercial only
- Does not represent a reliability imbalance, but a longer term “steady state imbalance
- Anything other than instantaneous balance is a commercial issue, not a reliability issue

Discussion and/or Agreement at NERC Drafting Team Meeting:

With the exception of language within the Policy regarding the RA’s ability to halt time error correction when system conditions warrant, the drafting team agreed to the NAESB recommendation. In general, the NAESB representatives agreed to this modification.

Action Plan:



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

NAESB will develop a business practice standard consistent with the requirements in Policy 1 Section D and Appendix 1D and shall “shadow” the NERC RA requirement as part of that standard.

Original Recommendation:

Section F “Inadvertent Interchange Standard”. NAESB would adopt this section of Policy 1 for inclusion in Version 0 business practices.

Reasoning as follows:

- Similar arguments to Section D.
- Scheduling of Inadvertent payback has significant financial and commercial implications

Discussion and/or Agreement at NERC Drafting Team Meeting:

Drafting team agreed to give NAESB requirement 5 (i.e. payback) and agreed that the accounting requirements (Requirement 4) should eventually go to NAESB, but not for Version 0. The NAESB representatives agreed to this modification to the recommendation for Version 0, but indicated that accounting procedures had significant commercial implications for settlement. As such, Version 1 changes to inadvertent business practice standards may include some accounting requirements.

Action Plan:

NAESB will develop a business practice standard consistent with the requirements in Policy 1 Section F Requirement 5 and shall “shadow” the business practices associated with Requirement 4.

### **Additional Policy 1 Discussion.**

Raymond Vice recommended giving Sections B, C, and D of Appendix 1A to NAESB. This will be asked as part of the NERC public comments. Depending upon the outcome of the comments, NERC may or may not convert these Sections of Appendix 1A into reliability standards.

Action Plan:

NAESB will develop a “shadow” business practice standard consistent with the requirements in Appendix 1A sections B, C, and D.

### **NERC Operating Policy 3 – “Interchange”**

Original Recommendation:

NAESB has already developed a version 1 Business Practice standard for Policy 3. This standard will be “reverted” into a Version 0 compatible standard.

Discussion and/or Agreement at NERC Drafting Team Meeting:

Roman Carter presented the breakout between NERC and NAESB, which recommended that all Policy 3 appendices stay with NERC for Version 0. For the most part, the team agreed to the



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

breakout as presented by Mr. Carter. There was some discussion regarding giving the Policy 3 appendices to NAESB. This will be asked as part of the NERC public comments. Depending upon these comments, NERC may determine to keep these appendices as part of the Version 0 reliability standards.

### Action Plan:

NAESB will develop the Version 0 Coordinate Interchange Business Practice Standard as presented by Mr. Carter, but will develop “shadow” business practices associated with Appendices 3A1, 3A2, 3A3, 3A4, and 3D.

### Original Recommendation:

NAESB will offer to adopt the E TAG Protocol Document (not the implementation) for inclusion in Version 0 business practices. It will be NERC’s decision whether to approve this adoption.

### Discussion and/or Agreement at NERC Drafting Team Meeting:

No decision was made regarding this although there was some general agreement that this could be handled by NAESB.

### Action Plan:

NAESB will open dialogue with NERC regarding this recommendation.

## **NERC Operating Policy 5 – “Emergency Operations”**

### Original Recommendation:

Section 5C “Capacity and Energy Emergencies”, Requirement 2.1 “Mitigating an Energy Emergency. NAESB would adopt language similar to the following as Version 0 business practices.

**Mitigating an Energy Emergency.** Balancing Authorities shall utilize the following actions to return ACE to acceptable levels during an energy emergency:

- Load all available generating capacity
- Utilize all operating reserves
- Interrupt all interruptible load and interruptible exports
- Utilize all emergency assistance from other BALANCING AUTHORITY

**Failure to Mitigate an Energy Emergency .** When Its ACE is negative and cannot be returned to zero in the next fifteen minutes utilize all of the above methods,

- The deficient Balancing Authority shall manually shed firm load without delay to return its ACE to zero.
- The deficient Balancing Authority shall declare an EMERGENCY ENERGY Alert in accordance with NERC Standards.

### Reasoning:

The language represents criteria and qualifications associated with declaring emergencies, which has significant commercial implications.



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

Discussion and/or Agreement at NERC Drafting Team Meeting:

The drafting team did not agree to remove the corresponding language from the reliability requirements because doing so would remove the original reliability intent, but agreed that NAESB should include the “shadow” business practice language in its Version 0 efforts.

It was also agreed that NAESB should expand upon those business practices as part of its Version 1 efforts.

Action Plan:

NAESB will develop the “shadow” Business Practice Standard represented by the language listed above.

Original Recommendation:

Section 5C “Capacity and Energy Emergencies”, Requirement 3 “Elevating Transmission Service Priority within the Eastern Interconnection”. NAESB would adopt this section for inclusion in Version 0 business practices using language similar to the following:

**Elevating Transmission Service Priority within the Eastern INTERCONNECTION.** A TRANSMISSION PROVIDER shall only elevate the transmission service priority of an INTERCHANGE

TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) if

- Permitted in its transmission tariff
- The LOAD-SERVING ENTITY served by the BALANCING AUTHORITY or TRANSMISSION PROVIDER has requested its RELIABILITY AUTHORITY to initiate an ENERGY EMERGENCY ALERT.
- The RELIABILITY AUTHORITY shall post the initiation of the Energy Emergency Alert and the expected total MW that may have its TRANSMISSION SERVICE priority changed on the NERC Web site

**Are these business requirements or reference material???**

**3.2.** EEA 1 will be used to *forecast* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

**3.3.** EEA 2 will be used to *announce* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

Reasoning:

- These requirement essentially represent a reallocation of firm service and therefore has commercial implications
- Generally speaking, rules governing when this can take place should be a commercial issue, not a reliability issue

Discussion and/or Agreement at NERC Drafting Team Meeting:

The drafting team did not agree to remove this language from the Version 0 reliability requirements because doing so would lose the context needed for the associated reliability





## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002  
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)  
Home Page: [www.naesb.org](http://www.naesb.org)

---

requirements, but agreed that NAESB should develop the “shadow” business practices inherent in the Policy.

### Action Plan:

NAESB will develop the “shadow” Business Practice Standard represented by the language listed above.

### Original Recommendation:

From Section 5D “Transmission”, Requirement 2 “Operating Authorities Shall Not Burden Others”. NAESB would adopt the language “In instances where there is a difference in derived operating limits the BULK ELECTIRC SYSTEM shall always be operated to the most limiting parameter” for inclusion in Version 0 business practices.

### Reasoning:

Business practices surrounding the resolution of differences in operating limits should be a commercial issue resolved within the context of other reliability requirements because of the potential impact on the market – it is not of itself a reliability requirement

### Discussion and/or Agreement at NERC Drafting Team Meeting:

The drafting team did not agree to this recommendation, because the Policy represents real time emergency condition. In that context, the NAESB representatives agreed that this would be more appropriately a reliability requirement and agreed to withdraw this recommendation at this time.

### Action Plan:

NAESB will not develop business practices associated with this requirement.

## **NERC Operating Policy 7 – “Telecommunications”**

### Original Recommendation:

NAESB will offer to adopt the ISN (Interregional Security Network) Communication Protocols as part of the Version 0 Business Practices. It will be NERC’s decision whether to approve this adoption.

### Discussion and/or Agreement at NERC Drafting Team Meeting:

Although there were no decisions made, there was a general agreement that protocol development and maintenance should be handled by NAESB. Mark Fidrych agreed to direct the Communication Subcommittee to work with NAESB on this issue.

### Action Plan:

NAESB will open dialogue with NERC regarding this recommendation.

## **NERC Appendix 9B – “Energy Emergency Alerts”**

### Original Recommendation:



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)

Home Page: [www.naesb.org](http://www.naesb.org)

---

Section A “General Requirements”. NAESB would adopt language similar to the following as part of its Version 0 efforts to capture the imbedded business practices contained within the Policy:

**Initiating an Energy Emergency Alert.** LOAD SERVING ENTITIES shall be allowed to initiate an Energy Emergency Alert for the following reasons

- When the LSE is, or expects to be, unable to provide its customers’ energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The LSE cannot schedule the resources due to, for example, ATC limitations or transmission loading relief limitations.

**Restrictions for Initiating Energy Emergency Alerts.** LOAD SERVING ENTITIES shall not initiate an Energy Emergency Alert based upon the cost of available resources

Discussion and/or Agreement at NERC Drafting Team Meeting:

The Drafting Team did not agree to remove these sections from the appendix, but agreed that Version 0 BPs are still needed.

Action Plan:

NAESB will develop the “shadow” Business Practice Standard represented by the language listed above.

### **NERC Appendix 9C1 – “Transmission Loading Relief”**

Original Recommendation:

NAESB will adopt all of appendix 9C1 (including 9C1B “Interchange Transaction Reallocation During TLR Levels 3a and 5a” and 9C1C “Interchange Transaction Curtailments During TLR Level 3B”) as companion Version 0 business practices. NERC may determine that there are certain reliability requirements that it needs to “section out” of this appendix as Version 0 reliability standards.

Discussion and/or Agreement at NERC Drafting Team Meeting:

NERC wants NAESB to adopt the appendix as is, but they will keep it in the NERC standards as-is as well and identify the core reliability elements embedded in it for Version 1.

Action Plan:

NAESB will develop a business practice standard consistent with the requirements in Policy 9 Appendix 9C1, 9C1B, and 9C1C.

### **NERC Appendix 9C2 – “WSCC Unscheduled Flow Reduction Procedure”**

Original Recommendation:

NAESB will adopt all of appendix 9C2, as is, for inclusion in Version 0 business practices. NERC may determine that there are certain reliability requirements that it needs to “section out” of this appendix as Version 0 reliability standards.



## North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: [naesb@naesb.org](mailto:naesb@naesb.org)

Home Page: [www.naesb.org](http://www.naesb.org)

---

Discussion and/or Agreement at NERC Drafting Team Meeting:

Similar discussion to 9C1 took place, but Ken Wilson says WECC doesn't want NAESB to adopt. NAESB will have to determine what needs to be done, but may just have to have a WECC regional difference.

Action Plan:

NAESB will not develop a business practice standard consistent with the requirements in Policy 9 Appendix 9C2 unless requested to do so through the NAESB standards request process. Furthermore, a regional difference will be incorporated into the Business Practice Standard associated with Appendix 9C1 that allows the WECC to utilize their own congestion management procedures.

### **NERC Appendix 9C3 – “ERCOT Operating Guide III, Operation to Maintain Transmission System Security”**

Original Recommendation:

NAESB will adopt all of appendix 9C3, as is, for inclusion in Version 0 business practices. NERC may determine that there are certain reliability requirements that it needs to “section out” of this appendix as Version 0 reliability standards.

Discussion and/or Agreement at NERC Drafting Team Meeting:

This particular ERCOT procedure is obsolete. The procedure hasn't been used for years. NAESB will have to have an ERCOT regional difference.

Action Plan:

NAESB will not develop a business practice standard consistent with the requirements in Policy 9 Appendix 9C3 unless requested to do so through the NAESB standards request process. Furthermore, a regional difference will be incorporated into the Business Practice Standard associated with Appendix 9C1 that allows ERCOT to utilize their own congestion management procedures.

# NAESB TIME ERROR CORRECTION STANDARD

Version 0

---

## 1. Requirements

- 1.1 **BALANCING AUTHORITIES operating asynchronously** may establish their own time error control bands, but must notify the NERC Resources Subcommittee of the bands being utilized, and also provide notification if they are changed.
  - 1.2 **The Operating Reliability Subcommittee shall designate**, on February 1<sup>st</sup> of each year, a RELIABILITY AUTHORITY to act as the Interconnection Time Monitor to monitor time error for each of the INTERCONNECTIONS and to issue time error correction orders.
  - 1.3 **Time Error Initiation.** Time error corrections will start and end on the hour or half-hour, and notice shall be given at least one hour before the time error correction is to start or stop. All BALANCING AUTHORITIES within an INTERCONNECTION shall make all Time Error corrections directed by the Interconnection Time Monitor for its INTERCONNECTION. All BALANCING AUTHORITIES within an INTERCONNECTION shall make Time Error Corrections at the same rate.
  - 1.4 **Interconnection Time Monitor.** Each Interconnection Time Monitor shall monitor time error and shall initiate or terminate corrective action orders according to the procedure specified in Appendix A, "Time Error Correction Procedure."
  - 1.5 **Time Error Correction labeling.** Time error correction notifications shall be labeled alphabetically on a monthly basis (A-Z, AA-AZ, BA-BZ,...).
  - 1.6 **Time correction offset.** The BALANCING AUTHORITY may participate in a Time Error Correction by either of the following two methods:
    - 1.6.1 **Frequency offset.** The Balancing Authority may offset its frequency schedule by 0.02 Hz, leaving the FREQUENCY BIAS SETTING normal, or
    - 1.6.2 **Schedule offset.** If the frequency schedule cannot be offset, the BALANCING AUTHORITY may offset its net INTERCHANGE schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the FREQUENCY BIAS SETTING).
  - 1.7 **Request for Termination or Halt of Scheduled Time Error Correction.** Any RELIABILITY AUTHORITY in an INTERCONNECTION may request the termination of a time error correction in progress. Any RELIABILITY AUTHORITY may request the halt of a scheduled time error correction that has not begun. BALANCING AUTHORITIES that have reliability concerns with the execution of a time error correction shall notify their RELIABILITY AUTHORITY and request the termination of a time error correction in progress. To enable NERC to track the results of the application of procedures relating to Time Control Standards, a RELIABILITY AUTHORITY requesting a termination or halt of a Time Error Correction shall forward an explanation for requesting the termination to the chairman of the Resources Subcommittee within 5 business days.
  - 1.8 **INTERCONNECTION time error notification.** The INTERCONNECTION Time Monitor shall on the first day of each month issue a notification of time error, accurate to within 0.01
-

second, to the other RELIABILITY AUTHORITYS within the INTERCONNECTION to assure uniform calibration of time standards.

- 1.9 Western INTERCONNECTION time error notification.** Within the Western INTERCONNECTION, the RELIABILITY AUTHORITY designated as the Interconnection Time Monitor shall provide the accumulated time error (accurate to within 0.001 second) to all BALANCING AUTHORITYS on a daily basis at 1400 PDT/PST using the WSCCNet. The alphabetic designator shall accompany time error notification if a time error correction is in progress.
- 1.10 Time correction on reconnection.** When one or more BALANCING AUTHORITYS have been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the time error of the INTERCONNECTION. A notification of the adjustment to time error shall be passed through Time Notification Channels as soon as possible after reconnection.
- 1.11 Leap seconds.** BALANCING AUTHORITYS using time error devices that are not capable of automatically adjusting for leap seconds shall arrange to receive advance notice of the leap second and make the necessary manual adjustment in a manner that will not introduce an improper INTERCHANGE SCHEDULE into their control system.

# Appendix A

## Time Error Correction Procedures

Version 0

Time	Initiation			Termination			Scheduled Freq – Hz
	East	West	ERCOT	East	West	ERCOT	
Slow	–10	–2	–3	–6	±0.5	±0.5	60.02
Fast	+10	+2	+3	+6	±0.5	±0.5	59.98

### Notes:

#### For the Eastern Interconnection:

1. No corrections for fast time will be initiated between 0400–1100 Central Time.
2. Corrections begin on the hour or half-hour.
3. Corrections shall last at least one hour, unless there is a cause for termination.

#### For all Interconnections:

1. A time correction may be halted, terminated, or extended if the designated Interconnection Time Monitor determines system conditions warrant such action.
2. After the premature termination of a manual time correction, a slow time correction can be reinstated after the frequency has returned to 60 Hz or above for a period of ten minutes. A fast time correction can be reinitiated after the frequency has returned to 60 Hz or lower for a period of ten minutes. At least one hour shall elapse, however, between the termination and re-initiation notices.

# NAESB TIME ERROR CORRECTION

## STANDARD

Started with File  
Policy 1 6-3-04.

## Policy 1 – Generation Control and Performance

Version 20

### ~~D. Time Control Standard 1. Requirements~~

~~[Appendix 1A — The Area Control Error Equation]  
[Appendix 1D — Time Error Correction Procedures]~~

### *Introduction*

INTERCONNECTION frequency is normally scheduled at 60.00 Hz and controlled to that value. The control is imperfect and over time the frequency will average slightly above or below 60.00 Hz resulting in electric clocks developing an error relative to true time. When the error exceeds pre-set limits, corrective action is taken by adjusting the scheduled frequency, a practice termed Time Error Correction. Each BALANCING AUTHORITY shall participate in Interconnection Time Error Correction procedures unless it is operating asynchronously to its INTERCONNECTION.

**1.1** BALANCING AUTHORITYs operating asynchronously may establish their own time error control bands, but must notify the NERC Resources Subcommittee of the bands being utilized, and also provide notification if they are changed.

**1.2** The Operating Reliability Subcommittee shall designate, on February 1<sup>st</sup> of each year, a RELIABILITY AUTHORITY to act as the Interconnection Time Monitor to monitor time error for each of the INTERCONNECTIONS and to issue time error correction orders.

### **1.3** Standard

~~1. Time error correction notice and commencement. Time error corrections shall be conducted in accordance with Appendix 1D, "Time Error Correction Procedure."~~

~~1.~~ **Time Error Initiation.** Time error corrections will start and end on the hour or half-hour, and notice shall be given at least one hour before the time error correction is to start or stop. All BALANCING AUTHORITYs within an INTERCONNECTION shall make all Time Error corrections directed by the Interconnection Time Monitor for its INTERCONNECTION. All BALANCING AUTHORITYs within an INTERCONNECTION shall make Time Error Corrections at the same rate.

The RS Recommends the SDT review the Performance Standard Reference Documents and incorporate applicable requirements into the Version 0. Into reference document and delete the entire body text. Note the is referenced throughout the Standard and the respective Appendixes.

The RS Recommends the SDT review all Operating Policy Waivers and incorporate them accordingly into the Version 0 Standards.

## Requirements

~~1.1.4~~ **Interconnection Time Monitor.** Each Interconnection Time Monitor shall monitor time error and shall initiate or terminate corrective action orders according to the procedure specified in Appendix ~~A1D~~, “Time Error Correction Procedure.”

~~2.1.5~~ **Time Error Correction labeling.** Time error correction notifications shall be labeled alphabetically on a monthly basis (A-Z, AA-AZ, BA-BZ,...).

~~3.1.6~~ **Time correction offset.** The BALANCING AUTHORITY may participate in a Time Error Correction by either of the following two methods:

~~1.1.1.6.1~~ **Frequency offset.** The Balancing Authority may offset its frequency schedule by 0.02 Hz, leaving the FREQUENCY BIAS SETTING normal, or

~~1.2.1.6.2~~ **Schedule offset.** If the frequency schedule cannot be offset, the BALANCING AUTHORITY may offset its net INTERCHANGE schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the FREQUENCY BIAS SETTING).

~~4.1.7~~ **Request for Termination or Halt of Scheduled Time Error Correction.** Any RELIABILITY AUTHORITY in an INTERCONNECTION may request the termination of a time error correction in progress. Any RELIABILITY AUTHORITY may request the halt of a scheduled time error correction that has not begun. BALANCING AUTHORITIES that have reliability concerns with the execution of a time error correction shall notify their RELIABILITY AUTHORITY and request the termination of a time error correction in progress. To enable NERC to track the results of the application of procedures relating to Time Control Standards, a RELIABILITY AUTHORITY requesting a termination or halt of a Time Error Correction shall forward an explanation for requesting the termination to the chairman of the Resources Subcommittee within 5 business days.

~~5.1.8~~ **INTERCONNECTION time error notification.** The INTERCONNECTION Time Monitor shall on the first day of each month issue a notification of time error, accurate to within 0.01 second, to the other RELIABILITY AUTHORITYS within the INTERCONNECTION to assure uniform calibration of time standards.

~~5.1.1.9~~ **Western INTERCONNECTION time error notification.** Within the Western INTERCONNECTION, the RELIABILITY AUTHORITY designated as the Interconnection Time Monitor shall provide the accumulated time error (accurate to within 0.001 second) to all BALANCING AUTHORITYS on a daily basis at 1400 PDT/PST using the WSCCNet. The alphabetic designator shall accompany time error notification if a time error correction is in progress.

~~6.1.10~~ **Time correction on reconnection.** When one or more BALANCING AUTHORITYS have been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the time error of the INTERCONNECTION. A notification of the adjustment to time error shall be passed through Time Notification Channels as soon as possible after reconnection.

~~7.1.11~~ **Leap seconds.** BALANCING AUTHORITYS using time error devices that are not capable of automatically adjusting for leap seconds shall arrange to receive advance notice of the leap second and make the necessary manual adjustment in a manner that will not introduce an improper INTERCHANGE SCHEDULE into their control system.



# Appendix ~~A1D~~—

## Time Error Co

RS Recommends Appendix 1D be considered a business practice along with Policy 1, Section D.

Version 20

Time	Initiation			Termination			Scheduled Freq – Hz
	East	West	ERCOT	East	West	ERCOT	
Slow	–10	–2	–3	–6	±0.5	±0.5	60.02
Fast	+10	+2	+3	+6	±0.5	±0.5	59.98

### Notes:

#### For the Eastern Interconnection:

1. No corrections for fast time will be initiated between 0400–1100 Central Time.
2. Corrections begin on the hour or half-hour.
3. Corrections shall last at least one hour, unless there is a cause for termination.

#### For all Interconnections:

1. A time correction may be halted, terminated, or extended if the designated Interconnection Time Monitor determines system conditions warrant such action.
2. After the premature termination of a manual time correction, a slow time correction can be reinstated after the frequency has returned to 60 Hz or above for a period of ten minutes. A fast time correction can be reinitiated after the frequency has returned to 60 Hz or lower for a period of ten minutes. At least one hour shall elapse, however, between the termination and re-initiation notices.

# NAESB Inadvertent Interchange Standard

---

Version 0

## General Requirements

---

1. **INADVERTENT INTERCHANGE Accounting.** ADJACENT BALANCING AUTHORITIES 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:
  - 1.1. **Daily accounting.** Each BALANCING AUTHORITY, by the end of the next business day, shall agree with its adjacent BALANCING AUTHORITIES to:
    - 1.1.1. The hourly values of Net Interchange Schedule.
    - 1.1.2. The hourly-integrated MWh values of Net Actual Interchange.
  - 1.2. **Monthly accounting.** 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. (Refer to **Appendix A, On Peak – Off Peak Periods**“
  - 1.3. **After-the-Fact Corrections.** After-the-fact corrections to the agreed-to Daily and Monthly accounting data shall only be made 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 the scheduled or actual values will not be accepted without agreement of the Adjacent BALANCING AUTHORITY (s).
  - 1.4. **Periodic Adjustments** shall be made to correct for differences between hourly MWh meter totals and the totals derived from register readings of the tie-line meters. Adjacent BALANCING AUTHORITIES shall agree upon the difference determined above and assign this correction to the proper On-Peak and Off-Peak period at the same times and in equal quantities in the opposite directions. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.
    - 1.4.1. Adjustments to schedules shall only be made if an incorrect schedule was used by one BALANCING AUTHORITY. Schedules shall not be adjusted after-the-fact due to marketing considerations or adjustments during the billing procedure.
2. **INADVERTENT INTERCHANGE payback.** Each BALANCING AUTHORITY shall be diligent in reducing accumulated inadvertent balances. INADVERTENT INTERCHANGE accumulations shall be paid back by either of the following methods:
  - 2.1. **Energy “in-kind” payback.** INADVERTENT INTERCHANGE accumulated during “On-Peak” hours shall only be paid back during “On-Peak” hours. INADVERTENT INTERCHANGE accumulated during “Off-Peak” hours shall only be paid back during “Off-Peak” hours. [See Appendix A, “On-Peak and Off-Peak Periods.”]

- 2.1.1. Bilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back via an INTERCHANGE SCHEDULE with another BALANCING AUTHORITY.
- 2.1.1.1. Opposite balances.** The SOURCE BALANCING AUTHORITY and SINK BALANCING AUTHORITY must have inadvertent accumulations in the opposite direction.
- 2.1.1.2. Agreement on schedule.** The terms of the inadvertent payback INTERCHANGE SCHEDULE shall be agreed upon by all involved BALANCING AUTHORITIES and TRANSMISSION PROVIDERS in accordance with NERC Interchange procedures.
- 2.1.2. Unilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a nonzero ACE ensures that the unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to BALANCING AUTHORITY 's L<sub>10</sub> limit and shall not burden the INTERCONNECTION.
- 2.2. Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT INTERCHANGE payback may be utilized.
- 3. INADVERTENT INTERCHANGE summary.** Each BALANCING AUTHORITY shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed **as specified below.**—These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE BALANCING AUTHORITIES, SINK BALANCING AUTHORITIES and all INTERMEDIARY BALANCING AUTHORITIES.
- 3.1. Summary balances.** 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.
- 3.2. Summary submission.** Each BALANCING AUTHORITY shall submit its monthly summary report to its Resources Subcommittee Survey Contact by the 15<sup>th</sup> calendar day of the following month. The Resources Subcommittee Survey Contact will prepare a composite tabulation and submit that tabulation to the NERC staff by the 22<sup>nd</sup> calendar day of the month.
- 3.2.1. Failure to Report.** A BALANCING AUTHORITY that neither submits a report nor supplies a reason for not submitting the required data by the 20th calendar day of the following month shall be considered non-compliant.
- 4. Dispute Resolution.** 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 resources subcommittee survey contact. The REPORT SHALL DESCRIBE THE NATURE AND THE CAUSE OF THE DISPUTE AS WELL AS A PROCESS FOR CORRECTING THE DISCREPANCY. The dispute resolution process is described in Appendix B,—Dispute Resolution Process.

## Appendix A – NAESB Inadvertent Interchange On- and Off-Peak Periods

---

### 1. *On-Peak and Off-Peak Hours (Monday Through Sunday)*

**On and Off-Peak designation.** The hourly inadvertent energy created by BALANCING AUTHORITIES is classified as either On-Peak or Off-Peak inadvertent. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

**Daylight saving time.** The On-Peak to Off-Peak and Off-Peak to On-Peak boundary hours are unaffected by transitions to or from daylight savings time. If BALANCING AUTHORITIES remains on either standard or daylight savings time throughout the year, their inadvertent accounting practices shall use prevailing time.

**On-peak hours.** Each INTERCONNECTION has a reference time zone and standardized On-Peak and Off-Peak periods. On-Peak periods are summarized in the table below for each INTERCONNECTION. Sundays and special holidays are designated to be Off-Peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as Off-Peak hours.

### 2. *On-Peak Hours For Monday Through Saturday In Hour-Ending Format*

<i>Interconnection</i>	<i>Reference Time Zone</i>	<i>Hour Ending</i>	
		<i>From</i>	<i>To</i>
Eastern	Central	0700	2200
ERCOT	Central	0800	2200
Western	Pacific	0700	2200

### 3. *Additional Off-Peak Holidays for the Eastern and Western Interconnections*

There are six identified U.S. holidays each year:

- New Year's Day
- Memorial Day
- Independence Day
- Labor Day
- Thanksgiving Day
- Christmas Day

If any of these holidays fall on a Sunday, the following Monday will be considered an Off-Peak day. Otherwise, the Off-Peak day will be the holiday itself.

## Appendix B – NAESB Inadvertent Interchange Dispute Resolution Process

---

### *Introduction*

Adjacent BALANCING AUTHORITIES that cannot mutually agree upon their respective Net Interchange quantities by the fifteenth calendar day of the following month shall submit a report to their respective Resources Subcommittee representative. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. Should the submitted processes not work, the process for resolving the dispute is described herein.

1. Regional Subcommittee Representative reporting requirements. The Resources Subcommittee representative shall accept the BALANCING AUTHORITY'S report describing the disputed values. To comply with the reporting requirements of NAESB Inadvertent Interchange Requirement 3. That representative shall contact the Resources Subcommittee representative for the opposing BALANCING AUTHORITY (if the dispute is between BALANCING AUTHORITIES in different Regions). The representative(s) shall determine a set of values, which will be reported to NERC. The report(s) will identify:
  - 1.1. The names of the disputing BALANCING AUTHORITIES.
  - 1.2. The reported monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing BALANCING AUTHORITIES.
  - 1.3. The mutually agreed to monthly Net Interchange Schedule (On-Peak and Off-Peak) between the disputing BALANCING AUTHORITIES (used to compute the Regional Inadvertent Interchange).
  - 1.4. The reported monthly NET ACTUAL INTERCHANGE (On-Peak and Off-Peak) between the disputing BALANCING AUTHORITIES.
  - 1.5. The mutually agreed to monthly Net Actual Interchange (On-Peak and Off-Peak) between the disputing BALANCING AUTHORITIES (used to compute the Regional Inadvertent Interchange).
2. NERC Staff reporting requirements. The NERC staff representative to the Resources Subcommittee shall receive the Regional reports and, using the mutually agreed to data, compile a balanced INADVERTENT INTERCHANGE SUMMARY report. This report will also include a tabulated list of the BALANCING AUTHORITIES that have disputed data, as well as the magnitude of the data in dispute. This report will be distributed to the Operating Committee as well as the Resources Subcommittee by the 1st of the succeeding month.
3. Dispute Resolution. All disputes between BALANCING AUTHORITIES within a Region shall be referred to the regional process for dispute resolution to resolve the dispute on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.

- 3.1. All disputes between BALANCING AUTHORITIES in different Regions shall be referred to the respective Regions' Operating Committee representatives, or other Regional-approved representatives, for resolution on an informal basis within 30 days of the issuance of the NERC INADVERTENT INTERCHANGE SUMMARY report.
  - 3.2. In the event that the informal procedures do not resolve the dispute within 30 days, the dispute shall be submitted to binding arbitration as described below.
4. Binding Arbitration. A professional arbitration service will provide each of the parties in the dispute an opportunity to be heard. Within 30 days of those presentations, the arbitrator shall issue a decision. The decision and the rationale for the decision shall be provided in writing to the disputing parties.

## Section F. Inadvertent Interchange Standard

4. **INADVERTENT INTERCHANGE Accounting.** ADJACENT ~~CONTROL AREAS~~ BALANCING AUTHORITIES shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each ~~CONTROL AREA~~ BALANCING AUTHORITY shall compute its INADVERTENT INTERCHANGE based on the following:
  - 4.1. **Daily accounting.** Each ~~CONTROL AREA~~ BALANCING AUTHORITY, by the end of the next business day, shall agree with its adjacent ~~CONTROL AREAS~~ BALANCING AUTHORITIES to:
    - 4.1.1. The hourly values of NET INTERCHANGE SCHEDULE.
    - 4.1.2. The hourly integrated MWh values of NET ACTUAL INTERCHANGE
  - 4.2. **Monthly accounting.** Each ~~CONTROL AREA~~ 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. [Refer to “Inadvertent Interchange Accounting Training Document”]
  - 4.3. **After-the-Fact Corrections.** After-the-fact corrections to the agreed-to Daily and Monthly accounting data shall only be made 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 ~~CONTROL AREA~~ ’s INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the ADJACENT ~~BALANCING AUTHORITY~~ CONTROL AREA (s).
5. **INADVERTENT INTERCHANGE payback.** Each ~~BALANCING AUTHORITY~~ CONTROL AREA shall be diligent in reducing accumulated inadvertent balances. INADVERTENT INTERCHANGE accumulations shall be paid back by either of the following methods:
  - 5.1. **Energy “in-kind” payback.** INADVERTENT INTERCHANGE accumulated during “onpeak” hours shall only be paid back during “on-peak” hours. INADVERTENT INTERCHANGE accumulated during “off-peak” hours shall only be paid back during “offpeak” hours. [See Appendix 1F, “On-Peak and Off-Peak Periods.”]
    - 5.1.1. **Bilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back via an INTERCHANGE SCHEDULE with another ~~BALANCING AUTHORITY~~ CONTROL AREA. [Refer to Policy 3, “Interchange” for Interchange Scheduling Requirements.]
      - 5.1.1.1. **Opposite balances.** The SOURCE ~~BALANCING AUTHORITY~~ CONTROL AREA and SINK ~~BALANCING AUTHORITY~~ CONTROL AREA must have inadvertent accumulations in the opposite direction.
      - 5.1.1.2. **Agreement on schedule.** The terms of the inadvertent payback INTERCHANGE SCHEDULE shall be agreed upon by all involved ~~BALANCING AUTHORITIES~~ CONTROL AREAS and TRANSMISSION PROVIDERS in accordance with NERC operating Policy 3, “Interchange.”
    - 5.1.2. **Unilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a nonzero ACE ensures that the

unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to BALANCING AUTHORITY's~~the CONTROL AREA's~~ L10 limit and shall not burden the INTERCONNECTION.

**5.2. Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT INTERCHANGE payback may be utilized.

**1. INADVERTENT INTERCHANGE summary.** Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in **Appendix 1F, "Inadvertent Interchange Energy Accounting Practices and Dispute Resolution Process."** These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

**1.1. Summary balances.** 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.

**1.2. Summary submission.** Each CONTROL AREA shall submit its monthly summary report to its Resources Subcommittee Survey Contact by the 15<sup>th</sup> calendar day of the following month. The Resources Subcommittee Survey Contact will prepare a composite tabulation and submit that tabulation to the NERC staff by the 22<sup>nd</sup> calendar day of the month.

**1.2.1. Failure to Report.** A CONTROL AREA that neither submits a report nor supplies a reason for not submitting the required data by the 20<sup>th</sup> calendar day of the following month shall be considered non-compliant.

**Dispute Resolution.** Adjacent CONTROL AREAS that cannot mutually agree upon their respective NET ACTUAL INTERCHANGE or NET SCHEDULED INTERCHANGE quantities by the 15<sup>th</sup> calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Resources Subcommittee Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in **Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures."**

## **C. On-Peak and Off-Peak Periods**

### **1. On-Peak and Off-Peak Hours (Monday Through Sunday)**

**On- and Off-Peak designation.** The hourly inadvertent energy created by a BALANCING AUTHORITY CONTROL AREA is classified as either On-Peak or Off-Peak inadvertent. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

**Daylight saving time.** The On-Peak to Off-Peak and Off-Peak to On-Peak boundary hours are unaffected by transitions to or from daylight savings time. If a BALANCING AUTHORITY CONTROL AREA remains on either standard or daylight savings time throughout the year, their inadvertent accounting practices shall use prevailing time.



**On-peak hours.** Each INTERCONNECTION has a reference time zone and standardized On-Peak and Off-Peak periods. On-Peak periods are summarized in the table below for each INTERCONNECTION. Sundays and special holidays are designated to be Off-Peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as Off-Peak hours.

**2. On-Peak Hours For Monday Through Saturday In Hour-Ending Format**

<u>Interconnection</u>	<u>Reference Time Zone</u>	<u>Hour Ending</u>	
		<u>From</u>	<u>To</u>
<u>Eastern</u>	<u>Central</u>	<u>0700</u>	<u>2200</u>
<u>ERCOT</u>	<u>Central</u>	<u>0800</u>	<u>2200</u>
<u>Western</u>	<u>Pacific</u>	<u>0700</u>	<u>2200</u>

**3. Additional Off-Peak Holidays for the Eastern and Western Interconnections**

There are six identified U.S. holidays each year:

- New Year's Day
- Memorial Day
- Independence Day
- Labor Day
- Thanksgiving Day
- Christmas Day

If any of these holidays fall on a Sunday, the following Monday will be considered an Off-Peak day. Otherwise, the Off-Peak day will be the holiday itself.

**AREA CONTROL ERROR (ACE) EQUATION SPECIAL CASES**

---

**Version 0*****Introduction***

In accordance with NERC Reliability Standards, it is the obligation of each BALANCING AUTHORITY to fulfill its commitment to the Interconnection and not burden the other BALANCING AUTHORITIES in the INTERCONNECTION. Each BALANCING AUTHORITY should minimize their effect on other BALANCING AUTHORITIES within the INTERCONNECTION. Any errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept between the involved parties and not passed to the INTERCONNECTION. In addition, this ACE should NOT include any offsets (e.g., unilateral inadvertent payback, Western INTERCONNECTION automatic time error control, etc.). This Standard provides the requirements of including the Jointly Owned Units, Supplemental Regulation Service and Load or Generation Transfer By Telemetry for the ACE calculations.

**1. Jointly Owned Units**

---

Jointly owned units (JOU) must be accounted for properly by all owners in the Area Control Error Equation.

- 1.1.** The following examples illustrate the methodology. BALANCING AUTHORITY X and BALANCING AUTHORITY Y each has a unit in their BALANCING AUTHORITY area jointly owned by both BALANCING AUTHORITIES. Unit 1 is in BALANCING AUTHORITY X and unit 2 is in BALANCING AUTHORITY Y. The ACE equation for BALANCING AUTHORITY X must reflect its ownership of both units. Two components are required: one to reflect X's ownership in unit 2 and one to reflect Y's ownership of unit 1. BALANCING AUTHORITY Y's ACE equation will likewise have two components, one for its ownership in unit 1 and one for X's ownership of unit 2. If fixed schedules aren't used, JOUs may be handled as a pseudo-tie or a dynamic schedule.

**1.1.1. Pseudo-Tie**

If the Jointly owned units are considered pseudo-ties then the  $NI_s$  remains prearranged schedules and the  $NI_A$  term becomes  $NI_a - I_{AJOUe} - I_{AJOUi}$  where:

$NI_a$  = actual tie flows.

$I_{AJOUe}$  = pseudo-tie for JOU external to a BALANCING AUTHORITY.

$I_{AJOUe}$  is assumed negative for external generation coming into the BALANCING AUTHORITY as a pseudo-tie.

$I_{AJOUi}$  = pseudo-tie for JOU internal to a BALANCING AUTHORITY.

Incoming power is negative.

Outgoing power is positive.

For example:

Assume Unit 1 in BALANCING AUTHORITY X is generating 400 MW.  
100 MW owned by X  
300 MW owned by Y

Assume Unit 2 in BALANCING AUTHORITY Y is generating 300 MW.  
50 MW owned by X  
250 MW owned by Y

Representing the units as a pseudo-tie the equations become:

For BALANCING AUTHORITY X:  $NI_A = NI_a - (-50) - 300$

For BALANCING AUTHORITY Y:  $NI_A = NI_a - (-300) - 50$

Note:  $I_{AJOU}$  is assumed negative for external generation coming into the BALANCING AUTHORITY as a pseudo-tie.

### 1.1.2. Dynamic Schedule

If reflected as a dynamic schedule, the  $NI_a$  remains actual tie flows and the  $NI_s$  becomes  $NI_s + I_{SJOU}$  +  $I_{SJOU}$ .

$NI_s$  = prearranged schedules.

$I_{SJOU}$  = dynamic schedule for JOU external to a BALANCING AUTHORITY.  
 $I_{SJOU}$  is assumed negative for external generation coming into the BALANCING AUTHORITY as a dynamic schedule.

$I_{SJOU}$  = dynamic schedule for JOU internal to a BALANCING AUTHORITY.

Incoming power is negative.

Outgoing power is positive.

For example:

Assume Unit 1 in BALANCING AUTHORITY X is generating 400 MW  
100 MW owned by X  
300 MW owned by Y

Assume Unit in BALANCING AUTHORITY Y is generating 300 MW  
50 MW owned by X  
250 MW owned by Y

Representing the unit as a dynamic schedule the equations become:

For BALANCING AUTHORITY X:  $NI_s = NI_s - 50 + 300$

For BALANCING AUTHORITY Y:  $NI_s = NI_s - 300 + 50$

Note:  $I_{\text{SJOU E}}$  is assumed negative for external generation coming into the BALANCING AUTHORITY as a dynamic schedule.

## 2. Supplemental Regulation Service

---

Supplemental regulation service is required when one BALANCING AUTHORITY takes over all or part of the regulation requirements of another BALANCING AUTHORITY without incorporating its ties and schedules. In this case, both BALANCING AUTHORITIES shall handle this in a consistent manner as a dynamic schedule

- 2.1. Both BALANCING AUTHORITIES shall add another component,  $I_{SC}$  to both BALANCING AUTHORITIES' ACE with the proper sign convention.
  - 2.1.1. Assume BALANCING AUTHORITY X is purchasing regulation service from BALANCING AUTHORITY Y.
    - 2.1.1.1. For BALANCING AUTHORITY X,  $I_{SC}$  shall be subtracted from BALANCING AUTHORITY X's ACE for over-generation and added for under-generation.
    - 2.1.1.2. For BALANCING AUTHORITY Y,  $I_{SC}$  shall be added to BALANCING AUTHORITY Y's ACE for X's over-generation and subtracted for X's under-generation

## 3. Load or Generation Transfer By Telemetry

---

Dynamic scheduling shall be used for telemetered transfer of load or generation from one BALANCING AUTHORITY to another.

- 3.1. Both BALANCING AUTHORITIES must modify their ACE equation.
  - 3.1.1. To transfer load, the BALANCING AUTHORITY giving up the transferred load shall add the load to its ACE equation ( $+I_{SL}$ ).
  - 3.1.2. The BALANCING AUTHORITY accepting the load shall subtract the transferred load from its ACE equation ( $-I_{SL}$ ).
  - 3.1.3. For generation, the BALANCING AUTHORITY giving up generation shall subtract it ( $-I_{SG}$ ) and the BALANCING AUTHORITY accepting the generation shall add it ( $+I_{SG}$ ) to its ACE equation.

## NAESB Coordinate Interchange Business Practice Standard, Version 0

### Definitions

For the purposes of this Standard, the following definitions shall be applied:

**Approval Entities** – Entities responsible for providing active approvals during the Market and/or Reliability Periods.

**Interchange Block Accounting** – Energy accounting that assumes a beginning and ending ramp time of zero minutes. For accounting purposes, this moves the energy associated with the starting and ending ramps into the adjacent starting and ending clock time of the Interchange.

**Market Period** – The period of time when a Requesting PSE is making purchase, sale, and Transmission service arrangements needed to support a Transaction Tag, including the period in which market approvals are obtained.

**Reliability Period** – The segment of time from when the Sink BA has received the “Implemented” Tag from the requesting PSE, or its designee, to physical implementation (beginning of ramp time).

**Requesting PSE** – The PSE submitting the Interchange Transaction Tag. Under current policy this entity would be called the “Tag Author”.

**Sink BA** – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of a bilateral Interchange.

**Source BA** – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of a bilateral Interchange.

### Business Practices

**1.0** All requests to implement bilateral Interchange Transactions shall be accomplished by the submission of a completed Interchange Transaction Tag to the Sink BA.

**1.1** A completed Tag shall contain, at a minimum, the NERC required information specified in the most current version of the **NAESB Appendix E “Required and Correctable Tag Data”**.

**1.2** It shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure the completed Tag has been submitted to the Sink BA.

**1.3** Entities shall only be allowed to take actions against tags as specified in most current version of the **NAESB Appendix D “Transaction Tag Actions”**.

**1.4** Transaction tags for Interchange crossing Interconnection Boundaries shall be in accordance with the most current version of the **NAESB Appendix B “Tagging Across Interconnection Boundaries”**.

**1.5** In the event of E-Tag system component failure, the requirements and procedures contained within the most current version of the **NAESB Appendix C “Electronic Tagging Service Performance Requirements and Failure Procedures”** shall be followed.

**2.0** All energy purchase, energy sale, and Transmission service arrangements necessary to create the Tag and implement the bilateral Interchange Transaction shall be performed prior to the Tag being submitted to the Sink BA.

**3.0** The Requesting PSE shall verify all necessary business and transmission arrangements prior to the Transaction Tag being submitting to the Sink BA. At its discretion, the Requesting PSE may defer this responsibility to the Market Operator Function.

**4.0** The completed Tag shall be submitted to the Sink BA in accordance with the timing requirements of the most current version of the **NAESB Appendix A “Submission and Response Timetables”**.

**5.0** The completed Tag shall be forwarded by the Sink BA to the appropriate Approval Entity for a Market Period assessment.

**6.0** The results of the Market Period assessment (approval or denial) by the Approval Entities shall be promptly communicated back to the Sink BA. The Sink BA shall notify the Requesting PSE and to all other involved parties the results of the assessment.

**6.1** All denials of a Transaction Tag by any Approval Entity shall be accompanied by the reason for such denial.

**7.0** Any changes to the status of the Tag during the Market Period assessment shall be communicated by the requesting PSE to the Sink BA.

**8.0** Until such time as NAESB establishes replacement protocols, the preferred method of submitting the Tag to the Sink BA shall be electronic and in accordance with the most current version of the E-Tag Specifications.

**8.1** A backup or redundant electronic system shall be available for immediate use should the primary electronic means become disabled.

**8.2** Submitting a Tag to the Sink BA via facsimile is acceptable only as a last resort when the electronic means and its required backup or redundant system are not available.

**9.0** Interchange Transaction Corrections to the Tag for non-reliability related data shall be allowed prior to the Tag's approval/denial by reliability Approval Entities.

**9.1** Timing for corrections shall be in accordance with the **NAESB Appendix A "Submission and Response Timetable"**.

**10.0** Interchange Transaction Modifications made to the "Implemented" Transaction Tag for market-related issues by the Requesting PSE, or their designee, must be submitted to the Sink BA and all affected parties within the time requirements of **NAESB Appendix A "Tag Submission and Response Timetable"**.

**10.1** If the Modification is denied by any Approval Entity, the original request remains valid for the original Tag duration period.

**11.0** All parties involved in the bilateral Interchange Transaction shall have, or arrange to have, personnel and facilities on site and immediately available 24 x 7 for notification of changes to the Request for Interchange.

**11.1** The personnel shall be available from the beginning of the Market Period until the Transaction has been completed.

**12.0** Unless provided for under a FERC approved market mechanism, energy accounting for all Transaction Tags shall be accomplished via Interchange Block Accounting.

**13.0** Settlement of losses shall be either handled as financial or as payment in-kind.



**13.1** For losses handled as payment in-kind, the Requesting PSE, or its designee, shall communicate to the Sink BA, via a Transaction Tag (either the original or separate Tag), the MW losses and the entity the losses are with for each TSP/BA along the Interchange path.

**14.0** Default ramp rates for the North American Interconnection shall be as follows:

**14.1** Default ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the Tag unless otherwise agreed to by all parties involved in the Tag .

**14.2** Default ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the Tag unless otherwise agreed to by all parties involved in the Tag.

# NAESB Appendix A –Tag Submission and Response Timetables

Version 0

## Appendix Subsections

A. Eastern Interconnection – New Transactions

B. Western Interconnection – New Transactions

C. Interchange Transaction Corrections

D. Interchange Transaction Modifications

## A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for 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 than 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” by the E-Tag system and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties.

The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation . This provision shall not be used to schedule TRANSACTIONS without the proper tag.

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 with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags with a duration of 24 hours or more must be evaluated in two hours.

### ***Timing Requirements for Reallocation when in a 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 by the Interchange Distribution Calculator no later than 35 minutes prior to the top of the hour to allow time for **RELIABILITY AUTHORITY** to assess the impact of reallocation.

## **B. Western Interconnection – New Transactions**

---

The tables below represent the recommended business practices for 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
<b>Notes/Clarification:</b> <ol style="list-style-type: none"> <li>1. All clock times are in PPT.</li> <li>2. Tags falling under the criteria in yellow are deemed pre-schedule tags.</li> <li>3. Tags falling under the criteria in green are deemed real-time tags.</li> <li>4. Pre-schedule tags submitted between 15:00 and 18:00 will be assigned LATE composite status.</li> <li>5. Real-time tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.</li> </ol> <b>*Start-time references are for start of the Transaction, not the start of the ramp.</b>					

Tag submission timing requirements are based on the type and duration of the TRANSACTION. Tags representing TRANSACTIONS that run for less than 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” by the E-Tag system and may be granted conditional approval.

Tags submitted that do not meet these requirements shall be considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties. The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation . This provision shall not be used to schedule TRANSACTIONS without the proper tag .

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 with a duration of 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.

## C. Interchange Transaction Corrections

---

TRANSACTION Corrections (as described in NAESB **Appendix E, “Required and Correctable Tag Data”**) may be provided by PSE submitting the Tag to replace non-reliability data listed in a tag. As each correction is received, the Evaluation Time of the TRANSACTION will extend, based on the following rules:

- Each correction shall extend the evaluation time by ten minutes
- At no time can the evaluation time be extended past the start time of the TRANSACTION.
- Each correction shall reset the approval status of those entities affected by the correction
- The segment or segments corrected will be eligible for passive approval if the correction is received within the timelines specified below, except in the case where the TRANSACTION has already been set for passive denial. The segment or segments corrected will be subject to passive denial if the correction is not received within the timelines specified below. At no point may a TRANSACTION segment already under Passive Denial constraints be returned to Passive Approval eligibility.

**Table 3: Correction Submission Requirements\***

Eastern Interconnection	Western Interconnection
20 minutes prior to start	30 minutes prior to start
*Start time references are for start of the Transaction not the start of the ramp.	

## D. 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 4: 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 5: Western Interconnection – Modifications**

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market – Committed Transmission Reservation(s) Reductions	N/A	N/A	N/A
Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes

**\*\*\*Start time references are for start of the Transaction not the start of the ramp.**

\*See Special Exception for Cancellations below

\*\*If received after deadline, requires active approval or will be passively denied

### Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the TRANSACTION **prior** to the start of a TRANSACTION but **following** that TRANSACTIONS approval. In the event that a **PSE** submitting the tag elects to cancel a TRANSACTION, the following timelines should be utilized:

**Table 6: 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.		

# NAESB Appendix B – Tagging Across Interconnection Boundaries

Version 0

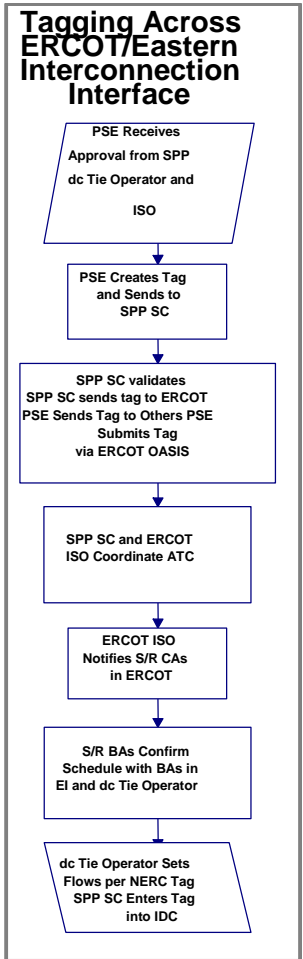
## A. Between ERCOT and Eastern Interconnections

A PURCHASING-SELLING ENTITY that is seeking transmission arrangements to schedule energy between the ERCOT and Eastern Interconnections will coordinate through the SPP RELIABILITY **AUTHORITY**. Requests for service must be made to the SPP RELIABILITY AUTHORITY for service into or through SPP (including service across either the North or East DC Ties) via the SPP OASIS. Request for service must also be made in ERCOT via the ERCOT OASIS. The SPP RELIABILITY AUTHORITY will coordinate approval of reservations and schedules involving the SPP portion of transmission service (including the DC ties) and service in ERCOT.

The following procedures are followed when scheduling transmission service between SPP and ERCOT:

- The PURCHASING-SELLING ENTITY must receive approval for DC tie service and transmission service in SPP from the SPP RELIABILITY AUTHORITY for the proposed transaction and arrange required ancillary services.
- For all transmission service requests, the PURCHASING-SELLING ENTITY will create a NERC Tag and submit it to the SPP RELIABILITY AUTHORITY. The SPP RELIABILITY AUTHORITY will validate certain information on the tag and check that a reservation exists before approving the tag. The approved tag will be available to the parties to the transaction and the ERCOT ISO.
- Simultaneous with submitting requests using the NERC TAG to the SPP RELIABILITY AUTHORITY (for next hour, non-firm and all other transmission service requests), the PURCHASING-SELLING ENTITY submits requests to the ERCOT ISO via the ERCOT OASIS. The MW profile information submitted to ERCOT must exactly match the information on the NERC Tag supplied to ERCOT by the SPP RELIABILITY AUTHORITY. (See note. )
- The SPP RELIABILITY AUTHORITY coordinates approval of the transaction if ATC is available in SPP and across the DC tie, and works with the ERCOT ISO to coordinate ATC calculations in ERCOT.
- The ERCOT ISO notifies the delivering/receiving ERCOT CONTROL AREA of the approved transaction and provides a copy of the NERC Tag and ERCOT schedule request.
- The delivering/receiving ERCOT BALANCING AUTHORITY communicates with the delivering/receiving control area outside of ERCOT, confirms the transaction/schedule, and confirms with the DC tie operator.
- The DC tie operator will follow the NAESB Tag when setting flows across the tie.

- 
- Note: In ERCOT, there are two types of wholesale transmission services—planned and unplanned. Planned Transmission Service is service for nominated generating resources to specified loads. All other transmission service is unplanned.





- The SPP RELIABILITY AUTHORITY will use the NAESB Tag to populate the IDC and to determine constrained facility ATC in the operating horizon.
- ERCOT ISO requires transactions/schedules involving use of the DC ties to include the NAESB Tag reference in the comments field on the ERCOT schedule request.

## **B. Between Western and Eastern Interconnections**

---

The WECC will use E-Tag for *pre-scheduled transactions* starting April 18, 2000, and for next hour and same day service wholly within WECC starting October 17, 2000. Due to the delay in implementing E-Tag for next hour and same day service, tagging requirements for these types of transactions shall remain unchanged within WECC.

### ***During the interim period of April 18, 2000 through October 17, 2000***

- All INTERCHANGE TRANSACTIONS that cross the Interconnection Boundary, including next hour and same day service, will be submitted in E-Tag format for inclusion in the Eastern Interconnection IDC.
- PURCHASING-SELLING ENTITIES from WECC submitting transactions shall provide E-Tag service or arrange for E-Tag services during this interim period.
- The requesting PURCHASING-SELLING ENTITY shall be responsible for the use of the WITHDRAW, CANCEL, TERMINATE, and REPLACEMENT features of E-Tag. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag changes either by fax or telephone to all WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path.
- WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path that have E-Tag capability shall initiate the ADJUST feature of E-Tag as required. WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path that do not have E-Tag capability shall communicate either by telephone or fax with a BALANCING AUTHORITY or TRANSMISSION SERVICE PROVIDER that does have E-Tag capability and arrange for the ADJUST message to be issued on their behalf.
- Any BALANCING AUTHORITY or TRANSMISSION SERVICE PROVIDER that requested an adjust by E-Tag shall also be responsible for communicating the tag changes either by fax or telephone to all WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path.

### ***Interchange Transaction where the sink is in the Eastern Interconnection***

- The PURCHASING-SELLING ENTITY serving the load shall be responsible for submitting the E-Tag.. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to

all WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path.

- The PURCHASING-SELLING ENTITY responsible for submitting the E-Tag will be required to submit the E-Tag in accordance with the time requirements in NAESB Appendix A, Subsection A – Eastern Interconnection.
- The TRANSMISSION SERVICE PROVIDERS and BALANCING AUTHORITIES responsible for assessing the E-Tag will be required to assess the E-Tag in accordance with the time requirements in NAESB Appendix A, Subsection A – Eastern Interconnection.

***Interchange Transaction where the Sink is in the Western Interconnection***

- For Pre-Scheduled Transactions, the PURCHASING-SELLING ENTITY serving the load shall be responsible for submitting the E-tag. The PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to all WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path.
- For Hourly/Multi-Hour Same Day Transactions, the sink PURCHASING-SELLING ENTITY in the Eastern Interconnection (last PSE before the DC Tie) shall be responsible for submitting the E-Tag. The sink PURCHASING-SELLING ENTITY shall also be responsible for communicating the tag information either by fax or telephone to all WECC BALANCING AUTHORITIES and TRANSMISSION SERVICE PROVIDERS on the Transaction Path.
- The PURCHASING-SELLING ENTITY responsible for submitting the E-Tag will be required to submit the E-Tag in accordance with the time requirements NAESB Appendix A, Subsection B – Western Interconnection.

The TRANSMISSION SERVICE PROVIDERS and BALANCING AUTHORITIES responsible for assessing the E-Tag will be required to assess the E-Tag in accordance with the time requirements in NAESB Appendix A, Subsection B – Western Interconnection

# **NAESB Appendix C – Electronic Tagging Service Performance Requirements and Failure Procedures**

---

## **Version 0**

This document describes the performance requirements of the E-Tag System and the procedures to be followed in the event of an E-Tag System Component's failure. Due to the importance of accurate information flow, these procedures and requirements have been developed to ensure that reliable data communications remain available at all times.

## **A. Performance Requirements**

---

### ***Tag Agent Service Requirements***

Entities that are required to use Tag Agent Services are responsible for providing a Tag Agent Service with which to conduct business; there are no exemptions to this requirement. There is no specific requirement against which performance should be measured. However, in cases of Tag Agent Service failure, non-receipt of critical information (such as curtailment notifications, transaction denials, and schedule modifications) due to performance problems shall be the responsibility of the Tag Agent user.

While it is acceptable for an entity to contract with a third-party to provide for this requirement, it should be understood that the Tag Agent User is ultimately responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

### ***Tag Approval Services***

Entities that are required to employ Tag Approval Services are responsible for providing a Tag Approval Service as well as providing a level of redundancy; there are no exemptions from this requirement. At a minimum, Tag Approval Services may not have greater than 1.0% of the tags sent to their system within a calendar month be recorded by Tag Authority Services as having a state of "COMM\_FAIL." While there is no specific level of redundancy that is required by this Appendix, sufficient redundancy must be in place that the entity is confident of achieving this standard.

While it is acceptable for an entity to contract with a third-party to provide for this requirement, it should be understood that the entity required to employ the Tag Approval Service is ultimately responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

In order to monitor compliance with this requirement, the Balancing Authorities will arrange with their Authority Services to generate compliance reports at the beginning of each month determining this metric for the previous month on a Provider-by-Provider basis. NAESB staff shall examine these results, investigate any violations, and post results based on this investigation as they are finalized.

## ***Tag Authority Services***

As the Tag Authority Service is the most critical element of the E-Tag System, it must meet much higher standards. These standards can be divided into two areas: Implementation, and Policies and Performance.

### ***Implementation***

Tag Authorities Services must be implemented in a manner that provides for redundancy and fault-tolerance through hardware and software; there are no exemptions to this requirement. Specifically, a Tag Authority Service must provide, at a minimum, the following:

- Two or more connections to the Internet, which may either be available concurrently or be switchable on demand (within five minutes);
- Redundant/Fault-Tolerant Networking Equipment between the Internet providers' demarcation points and the Computer Systems, as well as between each of the components of the system required to be inter-networked to provide functionality (i.e., FDDI Rings, dual homing, etc...);
- Redundant/Fault-Tolerant Computer Systems that can immediately recover from a loss of any single component (i.e., mirrored databases, web clusters, etc...).

Providers of Tag Authority Services must furnish NERC staff with documented explanations of how they meet or exceed the above requirements. These documents shall be evaluated by NAESB staff for fitness and held in confidence at the NAESB Offices.

### ***Policies and Performance***

The following shall be required of all Tag Authority Services:

- All scheduled outages must be performed between the hours of 01:00 CST and 04:00 CST. Any maintenance that must be performed outside this three hour window must be accomplished through the use of redundant systems in such a manner that no outage is visible;
- Notice of Scheduled outages must be given to the public at least 24 hours before the outage is to occur. Notice shall be deemed valid if the following actions have been taken:
  1. Users of the system are sent notifications, via Email or a proprietary system, time stamped at least 24 hours prior to the outage;
  2. The TISFORUM mailing list is sent Email notification time stamped at least 24 hours prior to the outage;
  3. The OASIS TSIN mailing list is sent Email notification time stamped at least 24 hours prior to the outage.

Any system problem that creates behavior contrary to that described in the E-Tag Specification shall constitute an “Unscheduled Outage.” For example, a system that begins rejecting every third message it receives due to a component failure in a cluster would constitute an Unscheduled Outage (although the system was only failing one third of the time, it was not performing as described in the E-Tag specification).

Tag Authority Services may not be in a state of Scheduled or Unscheduled outage for more than 0.5% of the time for the month, based on outage time (in minutes) for the month divided by total time in the month (in minutes). NAESB staff may grant specific allowed outages to address special circumstances (i.e., scheduled specification changes, major internet outages, etc...).

While it is acceptable for an entity to contract with a third-party to provide for these requirements, it should be understood that the entity required to employ the Tag Authority Service is ultimately responsible for the provision of the service. The non-performance of a third party does not excuse the entity from the obligation to provide the service.

To monitor compliance with these requirements, the Operator of a Tag Authority System must submit to NAESB staff, at the beginning of each month, a report describing outage activity for the previous month. This report shall consist of the following items:

1. The beginning of the outage;
2. The ending of the outage;
3. The type of outage (Scheduled or Unscheduled);
4. The nature of the outage (Maintenance, System Crash, etc...);
5. In the event of an Unscheduled Outage, the cause of the outage and the steps taken to ensure the problem has been addressed and will not reoccur.

NAESB staff shall specify the electronic format in which to send these reports. These documents shall be evaluated by NAESB staff and held in confidence at the NAESB office. NAESB staff shall develop statistics from these reports identifying system outage durations for each month. These preliminary findings will be held in confidence until NAESB staff confirms them. These performance percentages shall be posted on the NERC web site, following confirmation by NAESB staff, at the end of the month following the month evaluated.

Entities experiencing difficulty due to an Unnoticed Scheduled or Unscheduled Outage may send a Request for Investigation to NAESB staff. This request should specify the estimated time the outage occurred, the estimated time the outage ended, and document evidence of the outage (such as TMP logs, email messages, etc...). NAESB staff will investigate these claims with the appropriate Tag Authority Service Operator. Should a Tag Authority Service Operator be unable to refute the claim, and the Investigation Requestor appears to have provided an accurate representation of an undocumented outage, NAESB staff may choose to modify calculated outage percentages to include the undocumented incident.

## **B. Failure Procedures**

---

Backup procedures are needed because, in a communication system that operates on the public Internet, failures are certain to occur. The failures may be caused by as a result of overload of the network, loss of connection to an Internet service provider, corruption of one or more servers by computer hackers, failure of one or more entity's Internet servers, internal firewall failure, and many other reasons.

Failures also have a wide variety of scopes. A failure may affect a single entity with a small number of schedules while all of its neighbors continue to operate normally, a small number of utilities in a local area, or a regional RTO with thousands of active schedules. However failures occur, the operation of the electric utility grid must continue. This document describes the manner in which operations are to be coordinated should such a failure become a reality.

### ***Assumptions***

A general assumption is that each operational entity in the electric utility industry has an internal energy management system, marketing system, or contract system that will not be affected by the Internet communication failure.

### ***Actors***

Requesting PSE – The entity that prepares and submits a Tag.

Path Participant – Any of the entities that are part of a schedule transaction.

Authority Service entity – The entity that provides the Tag Authority Service for a tag. The Authority Service itself is a computer system that maintains the master database for the tag and communicates status with other computer systems. The Authority Service Entity is the utility industry entity that is responsible for providing the service. In E-Tag, this entity is the Load Control Area.

Approval Entity – An entity that has approval rights for a transaction. In E-Tag 1.7 this includes the transmission providers, scheduling control areas, generation providers, and load serving entities.

Checkout Partners – Any two entities in the utility industry that routinely perform a checkout confirmation of schedules for a period of time with each other. Most commonly two adjacent control areas checking net interchange. It might also be two marketers checking sales and purchases, or a transmission customer checking schedules with a transmission provider.

### ***Failure Actions***

When a failure occurs an entity will soon realize that it has lost communications with the other servers in the electronic tagging arena. Yet it must still communicate current energy flows across the transmission network and expected flows for the next few hours. Transmission curtailments must be accounted for in the sense that a required reduction in energy flows or increase in generation needs to be communicated. However, accounting issues will take a secondary priority to reliability issues in this exchange, and detail relating back to tags, schedules, and transmission reservations can be reconstructed later.

If adequate communication cannot be reestablished with other entities' scheduling systems the last resort will be to control by frequency.

The table below lists typical failures that might occur and the emergency actions that the entity will take to compensate for that failure.

<b>Entity</b>	<b>Connectivity Problem</b>	<b>Backup actions</b>
Requesting PSE	Unable to submit tag to Authority Service.	Ask another entity in the transaction chain to submit the schedule for you. He then becomes the author.  Create a backup paper copy of the schedule and fax to authority service entity and all approval entities in the transaction.
Path Participant	Not receiving update messages.	Use Recovery Process to resynchronize from authority service.  Use telephone with Authority Service Entity to update status.
Authority Service Entity	Unable to send messages to generation or load control area.	Telephone Schedule Author to notify of the message failure. The author will fax the schedule to the Approval Entity for these control areas.  Telephone Approval Entity to notify of the message failure.  Approve or deny the schedule at the request of the Approval Entity (override).
Authority Service Entity	Unable to send messages to an approval entity for an intermediate Transmission Provider or Control Area.	Telephone Schedule Author to notify of the message failure. The author will fax the schedule to the Approval Entity.  Telephone Approval Entity to notify of the message failure.  Approve the schedule automatically.  Deny the schedule at the request of the Approval Entity (override).
Authority Service Entity	Unable to send messages to an information only entity.	No Action required.
Authority Service Entity	Unable to receive messages.	Broadcast a message by email or fax to all entities that use your authority service. The message should forecast a recovery time for your service. In the meantime, your Authority Service is down.
Approval Entity	Unable to receive messages from an authority service. (The Authority has an obligation to notify you and the authoring PSE. The Authoring PSE has an obligation to fax the tag to the approver.)	Use the Recovery Process to resynchronize from Authority Services or Central Repository.  Telephone the Authority Service entity with the approval or denial of the schedule.
Approval Entity	Unable to send messages to an authority service.	Telephone the Authority Service Entity with approval or denial of the schedule.

<b>Entity</b>	<b>Connectivity Problem</b>	<b>Backup actions</b>
Checkout Partner	Unable to exchange messages.	Telephone net exchange to the checkout partner. Create a backup paper copy of the checkout data and fax to the checkout partner.

Notes:

1. The first action in every case is to attempt to establish connection by using an alternate communication method, a second Internet service provider, dial up connection, or a private network if one is available.
2. Next, the backup actions are attempted in the order specified.
3. The backup actions include printing paper reports from the internal energy management system. The reports include a schedule detail report for a short time period, net exchange between two operational entities, and transmission reservation usage between a transmission provider and a customer.
4. Every backup action list ends with a fax or telephone call that is completely independent of the public Internet.

## ***Reports***

Three reports have been designed to communicate energy flows and transmission reservation usage between partner entities with a tie where possible back to the schedules as known before the communication failure.

## ***Net Exchange***

A Net Exchange report is a paper summary of Interchange:

- The time span of the report will cover a period of the current hour to a few hours in the future, up to 24 hours.
- The entity and the partner entity are any two entities that share common schedules.
- The date and time are the date and time of the report.
- Net schedules are the net of schedules from and to the other entity.
- TO is a sum of the schedules from the entity to the partner entity.
- FROM is a sum of the schedules from the partner entity to the entity.
- Tag or fragment lines represent the data from each tag or fragment that was known at the time of the failure or has been entered later.
- Recent adjustment lines represent a summary of changes to the schedules that occurred since the failure.

## ***Schedule Detail***

A Schedule Detail report is a paper copy of an individual schedule. It includes:

- The schedule identification number and most current active revision number.



- The fully expanded energy schedule for a period of the current hour to a few hours in the future, up to 24 hours.
- The complete path with all OASIS and contract references.

### ***Reservation Usage***

A transmission Reservation Usage report is a summary of Reservation Usage:

- The time span of the report will cover a period of the current hour to a few hours in the future, up to 24 hours.
- The entities on the report are a transmission provider and a transmission contract holder.
- Gross reservations is the sum of reservations, Usage is the sum of usage.
- The detail lines are tag or fragment usage of reservation, organized by product and OASIS reservation number.

### ***Recovery Process***

The last backup issue is the recovery of current status when the communication link is reestablished. The recovery is accomplished by a query to the authority service for each entity that the entity does business with. The query returns a list of all the schedules that reference that entity with the schedule id, the current version number and the last modified date and time. The recovering entity then compares with its own database and updates his database to be current with the authority's database. When all authority services have been queried, the recovery is complete.

If the entity desires, it can request a complete audit history of each schedule.

# NAESB Appendix D – Transaction Tag Actions

## Version 0

### *For Eastern and Western Interconnections*

The table below explains the various tag actions that are possible, and the entities that are entitled to initiate these actions:

Desired Policy Action	Reason	Tagging Action	Initiated by	Result
Approve a Tag Request	Economic, Reliability, or Contractual	Set Status (to Approved)	Approval Entity*	Approver indicates approval
Deny a Tag Request	Economic, Reliability, or Contractual	Set Status (to Denied)	Approval Entity*	Approval indicates denial
Study a Tag Request	Economic, Reliability, or Contractual	Set Status (to Studied)	Approval Entity*	Approval indicates the tag has been viewed, but have not committed to a decision
Withdraw a Tag Request	Economic	Withdraw Request prior to request implementation	Requesting PSE**	Request is dead
Cancel a New Tag	Economic	Request Profile Change – Set Energy and Capacity for the transaction to zero prior to transaction start	Requesting PSE**	Tag is dead
Terminate a Tag	Economic	Request Profile Change – Set Energy and capacity of the transaction to zero from a point of time forward	Requesting PSE**	Portion of tag is dead
Extend a Tag	Economic	Request Profile Change – Append additional hours onto an existing transaction	Requesting PSE**	Tag is extended
Reduce a Tag	Economic	Request Profile Change – Decrease Energy flow or Committed Transmission Reservation(s) for a transaction for a specific set of hours	Requesting PSE**, Market Operator***	Profile is Decreased
Increase a Tag	Economic	Request Profile Change – Increase Energy flow or Committed	Requesting PSE**, Market Operator***	Profile is Increased

Desired Policy Action	Reason	Tagging Action	Initiated by	Result
		Transmission Reservation(s) for a transaction for a specific set of hours		
Curtail a Tag	Reliability (OSL Violation, Loss of Gen, loss of Load)	Request Profile Change – Limit Energy flow for a transaction for a specific set of hours	Source BA, Sink BA, Transmission Service Provider, Scheduling Agent	Profile is Decreased
Reload a Tag	OSL violation eliminated, Generator Returned, Load Returned	Request Profile Change – Release Limit of Energy flow for a transaction for a specific set of hours	Source BA, Sink BA, Transmission Service Provider, Scheduling Agent	Profile is Increased

Notes:

\*Purchasing-Selling Entities and LOAD-SERVING ENTITIES may elect to defer their approval rights to the HOST BALANCING AUTHORITY of their facilities. For more information, see PSE and LSE approval rights below

\*\*In some situations, **BALANCING AUTHORITIES** implement certain INTERCHANGE TRANSACTIONS or INTERCHANGE SCHEDULES, such as bilateral inadvertent payback, DYNAMIC SCHEDULES, and emergency schedules from RESERVE SHARING GROUPS. In these situations, the BALANCING AUTHORITY serves as the PURCHASING-SELLING ENTITY and can perform these actions.

\*\*\*Entities registered as market operators and serving as either source or sink for a TRANSACTION may exercise such functions in order to indicate correct flow based on market clearing.

### ***PSE and LSE Approval Rights***

PURCHASING-SELLING ENTITIES and LOAD-SERVING ENTITIES have been granted the right, but not the obligation, to approve TRANSACTION requests using their resources. If PSEs and LSEs specify an approval service in the Master Registry, then they are expected to approve/deny TRANSACTIONS when so requested. Otherwise, their HOST BALANCING AUTHORITY is expected to act on their behalf. The following table illustrates the proper way to interpret this requirement:

If the PSE...	Specified an Approval URL	The PSE should be granted rights to approve or deny
	Did not specify an Approval URL	The BA should have proxy approval rights for the PSE

# NAESB Appendix E – Required and Correctable Tag Data

---

Version 0

## Appendix Subsections

---

- A. New Transactions
  - B. Curtailments and Reloads (Reliability Profile Modifications)
  - C. Market Related Profile Modifications
- 

## A. New Transactions

---

A **new TRANSACTION** is a TRANSACTION that has not yet been implemented or confirmed for implementation. Such TRANSACTIONS must be presented to those entities that are responsible for the implementation of the TRANSACTION in order that they may **evaluate** the TRANSACTION request and determine whether or not the TRANSACTION can be implemented. The following information is to be used to describe such a TRANSACTION.

### 1. Market Information

- 1.1. Market Redispatch Information (only required if TRANSACTION is MRD TRANSACTION). (See “E-Tag Functional Specification Version 1.7”)
- 1.2. Financial Path (Required) – the description of financially responsible parties for the transaction in order. This will typically start with a **PURCHASING-SELLING ENTITY providing generation** and finish with a LOAD SERVING ENTITY, with optionally Intermediate PURCHASING-SELLING ENTITIES between the two.
  - 1.2.1. Energy Title Holder(s) (Required) – the identity of the entities financially responsible to take and/or deliver the energy as described in the physical path. This will typically be a **Purchasing-Selling Entity providing generation**, a LOAD SERVING ENTITY, and optionally Intermediate PURCHASING-SELLING ENTITIES.
    - 1.2.1.1. Energy Product Type (Correctable) – the type of energy delivered by the Energy Title Holder.
    - 1.2.1.2. Contract Number(s) (Correctable) – reference to a TRANSACTION entered into by the Energy Title Holder with one or more other participants in the TRANSACTION.
    - 1.2.1.3. Miscellaneous Information (Correctable) – information provided at the author’s option regarding the TRANSACTION.

### 2. Physical Information

- 2.1. Physical Path (Required) – the description of physically scheduling parties for the transaction in order and related to the financially responsible parties described above. This will always contain a Generation segment, at least one Transmission segment, and a LOAD segment.
  - 2.1.1. Generation (Required) – set of data describing the physical and contractual characteristics of the energy source.

- 2.1.1.1. Source (Required) – the physical point at which the energy is being generated. This may vary in granularity, dependent on local business practices.
- 2.1.1.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the **Purchasing-Selling Entity providing generation** and the Generator Operator.
- 2.1.1.3. Miscellaneous Information (Correctable) – information provided at the requesting PSE’s option regarding the TRANSACTION.
- 2.1.1.4. Energy Profile (Required) – energy to be produced by the Generator Owner for this TRANSACTION.
- 2.1.2. Transmission (Required) – set of data describing the physical and contractual characteristics of a wheel (import, export, or through).
  - 2.1.2.1. Transmission Service Provider (Required) – the identity of the transmission provider that is wheeling the energy.
  - 2.1.2.2. Point of Receipt (Correctable) – valid Point of Receipt for scheduled Transmission Reservation.
    - Point of Delivery (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.
    - **Scheduling Agent** (Correctable) – entity that is physically scheduling interchange on behalf of the TRANSMISSION SERVICE PROVIDER in order to provide wheeling services. Typically the BALANCING AUTHORITY for the TRANSMISSION SERVICE PROVIDER, but may be several **BALANCING AUTHORITIES** supporting a regional transmission service.
    - Loss Provision Information (Required) (Correctable)– Information describing the manner in which losses are accounted when they are not scheduled as in-kind megawatt distributions through the original transaction. Types may be financial (paid in dollars based on tariff provisions), internal (scheduled in megawatts to the TRANSMISSION SERVICE PROVIDER from a resource inside the TRANSMISSION **SERVICE PROVIDER’S AREA**), or external (scheduled in megawatts to the TRANSMISSION **SERVICE PROVIDER** from a resource outside the TRANSMISSION PROVIDER’S **AREA**). If internal or external, must specify contract numbers or TRANSACTION IDs.
    - Miscellaneous Information (Correctable) – information provided at the requesting PSE’s option regarding the transaction.
    - POR and POD Profiles (Required) – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.
    - Transmission Reservation Number(s) (Required) (Correctable) – reference to a particular transmission

reservation being used to provide transmission capacity to support the transaction being described.

- 2.1.2.2.1.** Transmission Product (Required) (Correctable) – Specifies the firmness of service associated with the transmission reservation being used.
- 2.1.2.2.2.** Requesting Purchasing-Selling Entity (Required) (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.
- 2.1.2.2.3.** Transmission Reservation Profile (Required) - information describing the transmission reservation commitment associated with the TRANSMISSION SERVICE PROVIDER.
  - 2.1.2.2.3.1.** Committed Transmission Reservation Level (Required) – schedule of transmission reservation committed by the requesting Purchasing-Selling Entity for use for this TRANSACTION.

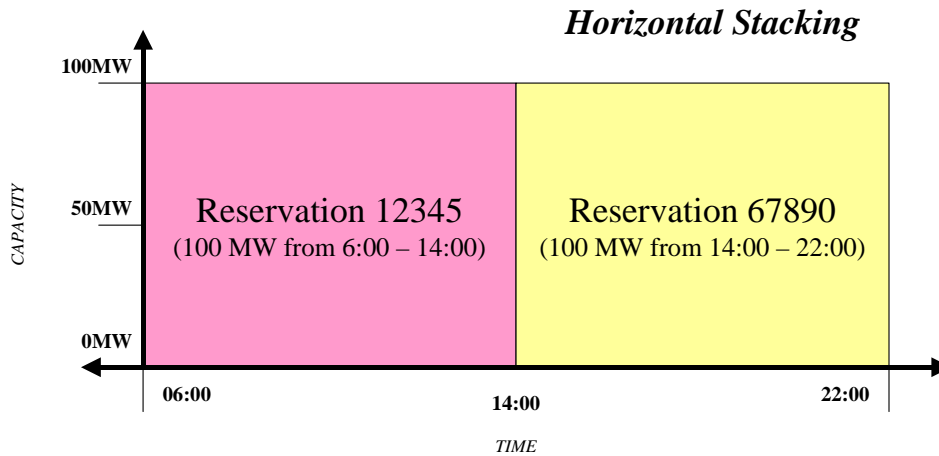
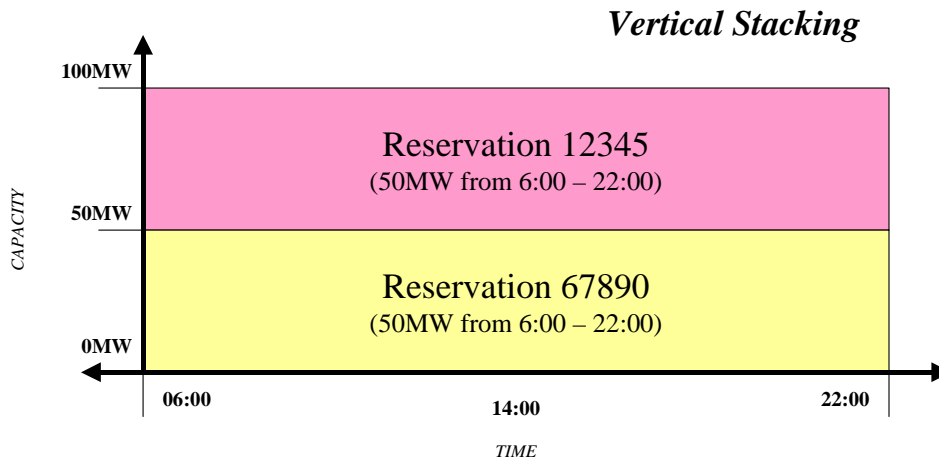
- 2.1.3.** Load (Required) – set of data describing the physical and contractual characteristics of the energy sink.
  - 2.1.3.1.** Sink (Required) – the physical point at which the energy is being consumed. This may vary in granularity, dependent on local business practices.
  - 2.1.3.2.** Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Load Serving Entity and the Distribution Provider.
  - 2.1.3.3.** Miscellaneous Information (Correctable) – information provided at the requesting PSE’s option regarding the TRANSACTION.
  - 2.1.3.4.** Energy Profile (Required) – energy to be consumed by the load for this TRANSACTION.

### ***Using Multiple Transmission Reservations to Support a Single Leg of an Interchange Transaction***

The use of multiple transmission reservations to support a single leg of an INTERCHANGE TRANSACTION is known as transmission **stacking**. There are two types of transmission stacking:

- Vertical stacking, in which a requesting Purchasing-Selling Entity combines multiple reservations to achieve a certain net level of transmission capacity, and
- Horizontal stacking, in which a requesting Purchasing-Selling Entity combines multiple reservations to achieve a certain transmission capacity coverage over time.

The following diagrams illustrate these concepts more fully. In both cases, the assumed need is 100 MW of transmission capacity for hours 06:00 through 22:00.



Should a requesting PSE elect to utilize stacking to support their INTERCHANGE TRANSACTION, they must understand the following requirements:

- Stacks **MUST** be described through fully qualified profiles for each reservation being used
- At no point may the coverage described by the stack be less than the transmission capacity needed for the TRANSACTION'S energy flow

## B. Curtailments and Reloads (Reliability Related Profile Modifications)

---

**Curtailments** and **Reloads** are special kinds of modifications to a transactions energy profile based on reliability concerns. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may **evaluate** the

transaction request and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The TRANSACTION being curtailed or reloaded
- All necessary profile changes to set the maximum flow allowed for the transaction during the appropriate hours
- A contact person that initiated the curtailment or reload, and
- A description of the necessity for the schedule change.

## **C. Market-Related Profile Modifications**

---

Profile Modifications are changes to a TRANSACTION'S energy profile based on market desires. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may **evaluate** the TRANSACTION request and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The TRANSACTION being modified
- All necessary profile changes to set the transmission capacity or energy flow to the desired levels during the appropriate hours, and
- A contact person that initiated the modification.





This Standard is developed using the Appendix 1A of NERC Operating Practices as a starting Point. The following is a redlined version after comparing the Standard with Appendix 1A.

## **Appendix 1A – The Area Control Error (ACE) Equation**

### **AREA CONTROL ERROR (ACE) EQUATION**

#### **Appendix Subsections**

##### **A. The ACE Equation**

##### **B. Jointly Owned Units**

###### **1. Pseudo-Tie**

###### **2. Dynamic Schedule**

##### **C. Supplemental Regulation Service**

1. **D. Load or Generation Transfer:** Jointly owned units (JOU) must be accounted for properly by **Telemetry** all owners in the Area Control Error Equation.

#### **Summary**

- 1.1. The following examples illustrate the methodology. BALANCING AUTHORITY X and BALANCING AUTHORITY Y each has a unit in their BALANCING AUTHORITY area jointly owned by both BALANCING AUTHORITIES. Unit 1 is in BALANCING AUTHORITY X and unit 2 is in BALANCING AUTHORITY Y. The ACE equation for BALANCING AUTHORITY X must reflect its ownership of both units. Two components are required: one to reflect X's ownership in unit 2 and one to reflect Y's ownership of unit 1. BALANCING AUTHORITY Y's ACE equation will likewise have two components, one for its ownership in unit 1 and one for X's ownership of unit 2. If fixed schedules aren't used, JOUs may be handled as a pseudo-tie or a dynamic schedule.

## **The ACE Equation**

It is the obligation of each CONTROL AREA to fulfill its commitment to the Interconnection and not burden the other CONTROL AREAS in the INTERCONNECTION. Each CONTROL AREA should minimize their effect on other CONTROL AREAS within the INTERCONNECTION. Any errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept between the involved parties and not passed to the INTERCONNECTION. In addition, this ACE should NOT include any offsets (e.g., unilateral inadvertent payback, Western INTERCONNECTION automatic time error control, etc.)

The equation for ACE is:

#### **1.1.1. Pseudo-Tie**

If the Jointly owned units are considered pseudo-ties then the  $NI_S$  remains prearranged schedules and the  $NI_A$  term becomes  $NI_a - I_{AJOU} - I_{AJOU}$  where:

## Appendix 1A – The Area Control Error (ACE) Equation

---

$NI_a$  = actual tie flows.

$I_{AJOE}$  = pseudo-tie for JOU external to a BALANCING AUTHORITY.

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

$I_{AJOE}$  is assumed negative for external generation coming into the BALANCING AUTHORITY as a pseudo-tie.

In this equation,  $NI_A$  accounts for all actual meter points that define the boundary of the CONTROL AREA and is the algebraic sum of flows on all tie lines. Likewise,  $NI_S$  accounts for all scheduled tie flows of the CONTROL AREA. The combination of the two ( $NI_A - NI_S$ ) represents the ACE associated with meeting schedules and if used by itself for control would be referred to as flat tie line regulation.

The second part of the equation,  $10\beta (F_A - F_S)$ , is a function of frequency. The  $10\beta$  represents a CONTROL AREA'S frequency bias ( $\beta$ 's sign is negative) where  $\beta$  is the actual frequency bias setting (MW/0.1 Hz) used by the CONTROL AREA and 10 converts the frequency setting to MW/Hz.  $F_A$  is the actual frequency and  $F_S$  is the scheduled frequency.  $F_S$  is normally 60 Hz but may be offset to effect manual time error corrections.

$I_{ME}$  is the meter error recognized as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW ( $NI_A$ ) and the hourly net interchange demand measurement (MWh). This term should normally be very small or zero.

## Jointly Owned Units

Jointly owned units (JOU) must be accounted for properly by all owners. The following examples illustrate the methodology. CONTROL AREA X and CONTROL AREA Y each has a unit in their CONTROL AREA jointly owned by both CONTROL AREAS. Unit 1 is in CONTROL AREA X and unit 2 is in CONTROL AREA Y. The ACE equation for CONTROL AREA X must reflect its ownership of both units. Two components are required: one to reflect X's ownership in unit 2 and one to reflect Y's ownership of unit 1. CONTROL AREA Y's ACE equation will likewise have two components, one for its ownership in unit 1 and one for X's ownership of unit 2. If fixed schedules aren't used, JOUs may be handled as a pseudo-tie or a dynamic schedule.

### 1. ~~Pseudo-Tie~~

If the Jointly owned units are considered pseudo-ties then the  $NI_s$  remains prearranged schedules and the  $NI_A$  term becomes  $NI_a - I_{AJOU} - I_{AJOU}$  where:

$NI_a$  = actual tie flows.

$I_{AJOU}$  = pseudo-tie for JOU external to a CONTROL AREA.

$I_{AJOU}$  is assumed negative for external generation coming into the CONTROL AREA as a pseudo-tie.

$I_{AJOU}$  = pseudo-tie for JOU internal to a CONTROL AREA BALANCING AUTHORITY.

Incoming power is negative.

Outgoing power is positive.

For example:

Assume Unit 1 in CONTROL AREA BALANCING AUTHORITY X is generating 400 MW.

100 MW owned by X

300 MW owned by Y

Assume Unit 2 in CONTROL AREA BALANCING AUTHORITY Y is generating 300 MW.

50 MW owned by X

250 MW owned by Y

Representing the units as a pseudo-tie the equations become:

For CONTROL AREA BALANCING AUTHORITY X:  $NI_A = NI_a - (-50) - 300$

For CONTROL AREA BALANCING AUTHORITY Y:  $NI_A = NI_a - (-300) - 50$

Note:  $I_{AJOU}$  is assumed negative for external generation coming into the CONTROL AREA BALANCING AUTHORITY as a pseudo-tie.

## Appendix 1A – The Area Control Error (ACE) Equation

---

### 1.1.2. Dynamic Schedule

If reflected as a dynamic schedule, the  $NI_a$  remains actual tie flows and the  $NI_s$  becomes  $NI_s + I_{SJOU E} + I_{SJOU I}$ .

$NI_s$  = prearranged schedules.

$I_{SJOU E}$  = dynamic schedule for JOU external to a ~~CONTROL AREA~~ BALANCING AUTHORITY.

$I_{SJOU E}$  is assumed negative for external generation coming into the ~~CONTROL AREA~~ BALANCING AUTHORITY as a dynamic schedule.

$I_{SJOU I}$  = dynamic schedule for JOU internal to a ~~CONTROL AREA~~ BALANCING AUTHORITY.

Incoming power is negative.

Outgoing power is positive.

For example:

Assume Unit 1 in ~~CONTROL AREA~~ BALANCING AUTHORITY X is generating 400 MW  
100 MW owned by X  
300 MW owned by Y

Assume Unit in ~~CONTROL AREA~~ BALANCING AUTHORITY Y is generating 300 MW  
50 MW owned by X  
250 MW owned by Y

Representing the unit as a dynamic schedule the equations become:

For ~~CONTROL AREA~~ BALANCING AUTHORITY X:  $NI_s = NI_s - 50 + 300$

For ~~CONTROL AREA~~ BALANCING AUTHORITY Y:  $NI_s = NI_s - 300 + 50$

Note:  $I_{SJOU E}$  is assumed negative for external generation coming into the ~~CONTROL AREA~~ BALANCING AUTHORITY as a dynamic schedule.

## Supplemental Regulation Service

---

2. Supplemental regulation service is required when one ~~CONTROL AREA~~ BALANCING AUTHORITY takes over all or part of the regulation requirements of another ~~CONTROL AREA~~ BALANCING AUTHORITY without incorporating its ties and schedules. In this case, both ~~CONTROL AREAS~~ BALANCING AUTHORITIES should handle this in a consistent manner as a dynamic schedule.  
~~Adding~~

- 2.1. Both ~~BALANCING AUTHORITIES~~ should add another component,  $I_{SC}$  to both ~~CONTROL AREAS~~ BALANCING AUTHORITIES ACE with the proper sign convention ~~will ensure proper control. Example:-~~

- 2.1.1. Assume ~~CONTROL AREA~~ BALANCING AUTHORITY X is purchasing regulation service from ~~CONTROL AREA~~ BALANCING AUTHORITY Y.

## Appendix 1A – The Area Control Error (ACE) Equation

---

- 2.1.1.1. For ~~area~~BALANCING AUTHORITY X,  $I_{SC}$  ~~would~~should be subtracted from ~~CONTROL AREA~~BALANCING AUTHORITY X's ACE for over-generation and added for under-generation. ~~Likewise, area Y's~~
- 2.1.1.2. ~~For~~ BALANCING AUTHORITY Y,  $I_{SC}$  ~~would~~should be added to ~~CONTROL AREA~~BALANCING AUTHORITY Y's ACE for X's over-generation and subtracted for X's under-generation.

## Appendix 1A – The Area Control Error (ACE) Equation

---

### Load or Generation Transfer By Telemetry

---

3. Dynamic scheduling ~~may also~~ should be used for telemetered transfer of load or generation from one CONTROL AREA BALANCING AUTHORITY to another. ~~Again both areas~~
- 3.1. Both BALANCING AUTHORITIES must modify their ACE equation.
- 3.1.1. To transfer load, the CONTROL AREA BALANCING AUTHORITY giving up the transferred load adds it should add the load to its ACE equation (+I<sub>SL</sub>).
- 3.1.2. The CONTROL AREA BALANCING AUTHORITY accepting the load subtracts it should subtract the transferred load from its ACE equation (-I<sub>SL</sub>). ~~Likewise for~~

For generation, the CONTROL AREA BALANCING AUTHORITY giving up generation subtracts should subtract it (-I<sub>SG</sub>) and the CONTROL AREA BALANCING AUTHORITY accepting the generation adds should add it (+I<sub>SG</sub>).

### Summary

---

3.1.3. ~~The ) to its ACE equation is:~~  
$$ACE = (NI_A - NI_S) - 10\beta (F_A - F_S) - I_{ME}$$

~~For the ERCOT INTERCONNECTION:—~~  
$$ACE = (NI_A - NI_S) + 10\beta (F_A - F_S)$$

~~Note: ERCOT defines  $\beta$  as a positive number~~

~~After considering regulation service and electronic load or generation transfer:~~

$$NI_A = NI_A$$
$$NI_S = NI_S \pm I_{SC} \pm I_{SG} \pm I_{SL}$$

~~If jointly owned units are treated as pseudo-ties:~~

$$NI_A = NI_A - I_{AJOU E} - I_{AJOU I}$$
$$NI_S = NI_S \pm I_{SC} \pm I_{SG} \pm I_{SL}$$

~~If jointly owned units are treated as dynamic schedules:~~

$$NI_A = NI_A$$
$$NI_S = NI_S - I_{SJOU E} + I_{SJOU I} \pm I_{SC} \pm I_{SG} \pm I_{SL}$$

~~To work properly, all transferred load or generation and all ties must be metered. All values of the ACE equation should be processed at the same time rate. A proper sign convention for load and generation must be agreed upon and adhered to by all involved CONTROL AREAS.~~

## **NAESB Coordinate Interchange Business Practice Standard, Version 0 Supporting Documentation**

### **Background:**

In light of the August 2003 Blackout, NERC is transitioning the existing Board-approved operating policies and planning standards, and the compliance templates approved by NERC Board on April 2, 2004 into an initial baseline Version 0 set of reliability Standards as recommended by the U.S.-Canada Power System Outage Task Force.

Current efforts are already under way by the NERC Coordinate Interchange Standard (Version 1) Drafting Team to address the reliability issues associated with bilateral Interchange Transactions. The Version 1 Standard is being developed using the Functional Model as a basis for defining the “Functions” necessary for Bulk Electric System reliability rather than the existing NERC Operating Policies for “Control Areas”.

NERC’s Version 0 Standard Drafting Team will be responsible for a Version 0 Standard that will address Policy 3 reliability issues prior to the above-mentioned Version 1 Standard being enforced. The Version 0 Standard will also utilize the Functional Model language but will not incorporate the new Interchange Authority Entity. Instead, it refers to the Sink Balancing Authority (Sink BA) for Entities performing functions which the IA would perform under Version 1.

### **Introduction:**

The NAESB Business Practices Subcommittee (BPS) is in the development stages of producing its complementary Version 0 Standards which will encompass the business practices currently contained within the NERC Operating Policies.

The NAESB Coordinate Interchange Standard Version 0 presented here identifies market-supported processes necessary to facilitate bilateral Interchange Transactions prior to the implementation of the approved NAESB CIBP Standard (Version 1). It specifies the arrangements that need to be made and the data that needs to be communicated to the Sink BA and to all involved parties of the Interchange Transaction Tag in order for Interchange transactions to take place between the Source and Sink Balancing Authorities.

This Standard only covers the business arrangements, data, and timing requirements necessary to submit the Transaction Tag to the Sink BA. It recognizes that FERC- approved tariffs may supersede some provisions in this Standard.

The Standard applies Functional Model definitions to provide consistency with NERC’s reliability Standards. However, like the NERC Version 0 Standards, this Standard will not incorporate the Interchange Authority entity.

Attached below are the Policy 3 requirements highlighted in blue from which the Version 0 Standard bases its requirements upon.

---

---



---

# Policy 3 – Interchange

---

Version 0 – Draft 01

Key:

Yellow Reliability Related

Notes

Blue NAESB

Version 5.2

[See also, “Interchange Reference Document”]

## ***Policy Subsections***

---

- A. Interchange Transaction Implementation**
  - B. Interchange Schedule Implementation**
  - C. Interchange Schedule Standards**
  - D. Interchange Transaction Modifications**
- 

## ***Introduction***

This Policy addresses the following issues:

- Responsibilities of all PURCHASING-SELLING ENTITIES involved in INTERCHANGE TRANSACTIONS.
- Information requirements for INTERCHANGE TRANSACTIONS.
- Requirements of BALANCING AUTHORITY (BA) , RELIABILITY AUTHORITY (RA), AND TRANSMISSION SERVICE PROVIDER (TSP) to assess and confirm INTERCHANGE TRANSACTIONS.
- Accountability of BA for implementing all INTERCHANGE SCHEDULES in a manner that ensures the reliability of the INTERCONNECTIONS.
- Standards for INTERCHANGE SCHEDULES between Source and Sink BAs.
- Requirements for INTERCHANGE TRANSACTION Cancellation, Termination, and Curtailment.

## A. Interchange Transaction Implementation

---

[Policy 2A, “Transmission—Transmission Operations”]

[Appendix 3A1, “Tag Submission and Response Timetables”]

[Appendix 3A2, “Tagging Across Interconnection Boundaries]

[“E-Tag Spec”]

[“Transaction Tagging Process within ERCOT Reference Document”]

---

### *Introduction*

This section specifies the PURCHASING-SELLING ENTITY’S requirements for tagging all INTERCHANGE TRANSACTIONS, the Balancing Authorities’ and TRANSMISSION SERVICE PROVIDERS’ obligations for accepting the tags, and the BA’S obligation for implementing the INTERCHANGE TRANSACTIONS. The tag data is integral for providing the BA , RA and TSP, and other operating entities the information they need to assess, confirm, approve or deny, implement, and curtail INTERCHANGE TRANSACTIONS as necessary to accommodate the marketplace and ensure the operational security of the INTERCONNECTION.

### *Requirements*

- 1. INTERCHANGE TRANSACTION arrangements.** The PURCHASING-SELLING ENTITY shall arrange for all Transmission Services, tagging, and contact personnel for each INTERCHANGE TRANSACTION to which it is a party.

**NAESB REQUIREMENT 3.0**

**1.1 Transmission services.** The PURCHASING-SELLING ENTITY shall arrange the Transmission Services necessary for the receipt, transfer, and delivery of the TRANSACTION.

**NERC requires Transmission Service Provider to review prior to approving tag.**

**NAESB REQUIREMENT 2.0, 3.0**

**1.2 Tagging.** The PURCHASING-SELLING ENTITY serving the load shall be responsible for providing the INTERCHANGE TRANSACTION tag. (Note: 1. Any PSE may provide the tag; however, the load-serving PSE is responsible for ensuring that a single tag is provided. 2. If a PSE is not involved in the TRANSACTION, such as delivery from a jointly owned generator, then the SINK BA is responsible for providing the tag. PSEs must provide tags for all INTERCHANGE TRANSACTIONS in accordance with Requirement 2 below)

**Covered under NERC V-0 Standard.**

**NAESB REQUIREMENT 1.2**

**1.3 Contact personnel.** Each PURCHASING-SELLING ENTITY with title to an INTERCHANGE TRANSACTION must have, or arrange to have, personnel directly and immediately available for notification of INTERCHANGE TRANSACTION changes. These personnel shall be available from the time that title to the INTERCHANGE TRANSACTION is acquired until the INTERCHANGE TRANSACTION has been completed. **NAESB REQUIREMENT 11.0**

## Policy 3 – Interchange

### A. Interchange Transaction Implementation

**1.4 E-Tag monitoring.** Each BA, RA, TSP, and PSE who are responsible for a tagged TRANSACTION shall have facilities to receive unsolicited notification from the Sink BA of changes in the status of a tag with which the user is a participant.

#### NAESB REQUIREMENT 11.0

**2.0 INTERCHANGE TRANSACTION tagging.** Each INTERCHANGE TRANSACTION shall be tagged before implementation as required by each INTERCONNECTION as specified in the **“E-Tag Spec”** or **“Transaction Tagging Process within ERCOT Reference Document.”** In addition to providing necessary operating information, the INTERCHANGE TRANSACTION tag is the official request from the load-serving PURCHASING-SELLING ENTITY to the SINK BA to implement the INTERCHANGE TRANSACTION. The information that must be provided on the tag is listed in **Appendix 3A4.**

#### NAESB REQUIREMENT 1.1

**2.1 Application to TRANSACTIONS.** All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged.

#### COVERED UNDER NERC V-0 STANDARD

#### NAESB REQUIREMENT 1.0

In addition, intra-BA transfers using Point-to-Point Transmission Service<sup>1</sup> shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between BAs).
- TRANSACTIONS that are entirely within a BA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the Sink BA).
- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by Sink BA). [See also, Policy 1E2 and 2.1, **“Disturbance Control Standard”**]

#### COVERED UNDER NERC V-0 STANDARD

**2.2 Parties to whom the complete tag is provided.** The tag, including all updates and notifications, shall be provided to the following entities:

- Purchasing-Selling Entities
- Balancing Authorities
- TRANSMISSION SERVICE PROVIDERS

---

<sup>1</sup> This includes all “grandfathered” and other “non-888” Point-to-Point Transmission Service

## Policy 3 – Interchange

### A. Interchange Transaction Implementation

---

- GENERATOR OWNERS
- LOAD-SERVING ENTITIES
- RELIABILITY AUTHORITIES
- Security Analysis Services

**COVERED UNDER NERC V-0 STANDARD**

**NAESB REQUIREMENT 5.0**

**2.3 Method of transmitting the tag.** The PURCHASING-SELLING ENTITY shall submit the INTERCHANGE TRANSACTION tag in the format established by each INTERCONNECTION. [**“E-Tag Spec”** or **“Transaction Tagging Process within ERCOT Reference Document”**]

**NAESB REQUIREMENT 8.0**

**2.3.1 Tags for INTERCHANGE TRANSACTIONS that cross INTERCONNECTION boundaries.** Procedures are found in **Appendix 3A2, “Tagging Across Interconnection Boundaries.”**

**COVERED UNDER NERC V-0 STANDARD**

**2.4 INTERCHANGE TRANSACTION submission time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTIONS shall be submitted to the Sink BA and assessed by the RA, BA, TSP as specified in **Appendix 3A1, “Tag Submission and Response Timetable.”**

**COVERED UNDER NERC V-0 STANDARD**

**NAESB REQUIREMENT 4.0**

**2.4.1 Exception for security reasons.** Exception to the submission time requirements in Section 2.4 is allowed if immediate changes to the INTERCHANGE TRANSACTIONS are required to mitigate an OPERATING SECURITY LIMIT violation. The tag may be submitted after the emergency TRANSACTION has been implemented but no later than 60 minutes.

**COVERED UNDER NERC V-0 STANDARD**

**2.5 Confirmation of tag receipt.** Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. [**“E-Tag Spec”**]

**NAESB REQUIREMENT 6.0**

## Policy 3 – Interchange

### A. Interchange Transaction Implementation

**2.6 Tag acceptance.** An INTERCHANGE TRANSACTION tag shall be accepted if all required information is valid and provided in accordance with the tagging specifications in Requirement 2.

Not in NAESB or NERC Standard

**3.0 INTERCHANGE TRANSACTION tag receipt verification.** The SINK BA shall verify the receipt of each INTERCHANGE TRANSACTION tag with the Transmission Providers and Balancing Authorities before the INTERCHANGE TRANSACTION is implemented.

NAESB REQUIREMENT 6.0

**4.0 INTERCHANGE TRANSACTION assessment.** All TRANSMISSION SERVICE PROVIDERS, LOAD SERVING ENTITIES, PURCHASING-SELLING ENTITIES and BALANCING AUTHORITIES involved in the transaction, and other operating entities responsible for operational security shall be responsible for assessing and “approving” or “denying” INTERCHANGE TRANSACTIONS as requested by the PSE based on established reliability criteria and adequacy of INTERCONNECTED OPERATIONS SERVICES and transmission rights as well as the reasonableness of the INTERCHANGE TRANSACTION tag. PURCHASING-SELLING ENTITIES and LOAD SERVING ENTITIES may elect to defer their approval responsibility to the Host BA. This assessment shall include the following:

NERC expects that Approval Entities have the proper resources to perform these assessments. Lack of these tools is not a reason to deny an Interchange Transaction. Resources include personnel and tools.

**The BA assesses:**

- TRANSACTION start and end time
- ENERGY PROFILE (ABILITY OF GENERATION MANEUVERABILITY TO ACCOMMODATE)
- SCHEDULING PATH (proper connectivity of ADJACENT BAs)

**The TRANSMISSION PROVIDER assesses:**

- Valid OASIS reservation number or transmission contract identifier
- Proper transmission priority
- Energy profile accommodation (does energy profile fit OASIS reservation?)
- OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS
- Loss accounting

COVERED UNDER NERC V-0 STANDARD

NAESB REQUIREMENT 1.1, 6.0

**The PURCHASING-SELLING ENTITY and LOAD-SERVING ENTITY assess**

- Transaction is valid representation of contractually agreed upon energy delivery.

**NAESB REQUIREMENT 2.0, 3.0**

- **Tag corrections.** During the BA's and TSP's assessment time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all BAS and TSPs on the Scheduling Path, or the completion and submission of a new tag by the PURCHASING-SELLING ENTITY. The SINK BA shall notify the BAS and TSPs, as to the changes and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in **Appendix 3A1, "Tag Submission and Response Timetable."** Tag items that may be corrected are found in **Appendix 3A4, "Required Tag Data."** A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in **Appendix 3D, "Transaction Tag Actions."** [See **Appendix 3A1 Subsection C, Interchange Transaction Corrections.**]

**NAESB REQUIREMENT 9.0**

**5.0 INTERCHANGE TRANSACTION approval or denial.** Each BA and TSP involved in the transaction responsible for assessing and "approving" or "denying" the INTERCHANGE TRANSACTION shall notify the Sink BA as to the results of the assessment. The SINK BA in turn notifies the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag, plus all Balancing Authorities and TRANSMISSION PROVIDERS on the Scheduling Path. Assessment timing requirements are found in **Appendix 3A1, "Tag Submission and Response Timetable."** A description of those entities who may approve or deny an INTERCHANGE TRANSACTION is found in **Appendix 3D, "Transaction Tag Actions."**

**COVERED UNDER NERC V-0 STANDARD**

**NAESB REQUIREMENT 6.0**

**5.1 INTERCHANGE TRANSACTION denial.** If denied, this notification shall include the reason for the denial.

**NAESB REQUIREMENT 6.1**

**5.2 INTERCHANGE TRANSACTION approval.** The INTERCHANGE TRANSACTION is considered approved if the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag has received confirmation of tag receipt and has not been notified that the transaction is denied.

**NOT SPECIFICALLY COVERED IN NAESB OR NERC STANDARD**

## Policy 3 – Interchange

### A. Interchange Transaction Implementation

---

**6.0 Responsibility for INTERCHANGE TRANSACTION implementation.** The SINK BA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of BALANCING AUTHORITIES ON THE SCHEDULING PATH in accordance with Policy 3B.

**COVERED UNDER NERC V-0 STANDARD**

**6.1 Tag requirements for INTERCHANGE TRANSACTION implementation.** The BA shall implement only those INTERCHANGE TRANSACTIONS that:

- Have been tagged in accordance with Requirement 2 above, or,
- Are exempt from tagging in accordance with Requirement 2.1 above.

**COVERED UNDER NERC V-0 STANDARD**

**7. Tag requirements after curtailment has ended.** After the curtailment of a TRANSACTION has ended, the INTERCHANGE TRANSACTION'S energy profile will return to the originally requested level unless otherwise specified by the PURCHASING-SELLING ENTITY. [See **Interchange Transaction Reallocation During TLR Levels 3a and 5a Reference Document, Version 1 Draft 6.**]

**COVERED UNDER NERC V-0 STANDARD**

**8.0 Confidentiality of information.** RELIABILITY AUTHORITIES, BAs, TRANSMISSION PROVIDERS, PURCHASING-SELLING ENTITIES, and entities serving as tag agents or service providers as provided in the “**E-Tag Spec**” shall not disclose INTERCHANGE TRANSACTION information to any PURCHASING-SELLING ENTITY except as provided for in Requirement 2.2 above, “**Parties to whom the complete tag is provided.**”

**Not Covered in NAESB or NERC Standard**

## B. Interchange Schedule Implementation

[Policy 2A, “Transmission—Transmission Operations”]

### *Introduction*

This section explains CONTROL AREA requirements for implementing the INTERCHANGE SCHEDULES that result from the INTERCHANGE TRANSACTIONS tagged by the PURCHASING-SELLING ENTITIES in Section A.

### *Requirements*

1. **BALANCING AUTHORITIES must be adjacent** .INTERCHANGE SCHEDULES shall only be implemented between ADJACENT BALANCING AUTHORITIES.

**COVERED UNDER NERC V-0 STANDARD**

2. **Sharing INTERCHANGE SCHEDULES details.** The SENDING AND RECEIVING BAS must provide the details of their INTERCHANGE SCHEDULES via the Interregional Security Network as specified in Policy 4.B.

**COVERED UNDER NERC V-0 STANDARD**

3. **Providing tags for approved TRANSACTIONS to the RELIABILITY AUTHORITY.** The SINK BA shall provide it's RELIABILITY AUTHORITY the information from the INTERCHANGE TRANSACTION tag electronically for each Approved INTERCHANGE TRANSACTION.

**COVERED UNDER NERC V-0 STANDARD**

4. **INTERCHANGE SCHEDULE confirmation and implementation.** The RECEIVING BA is responsible for initiating the confirmation and implementation of the INTERCHANGE SCHEDULE with the SENDING BA .

**COVERED UNDER NERC V-0 STANDARD**

- 4.1. **INTERCHANGE SCHEDULE agreement.** The SENDING AND RECEIVING BA shall agree with each other on the:

- INTERCHANGE SCHEDULE start and end time
- Ramp start time and rate
- Energy profile

This agreement shall be made before either the SENDING OR RECEIVING BA makes any generation changes to implement the INTERCHANGE SCHEDULE.

**COVERED UNDER NERC V-0 STANDARD .**



**B. Interchange Schedule Implementation**

- 4.1.1. INTERCHANGE SCHEDULE standards.** The SENDING AND RECEIVING BA shall comply with the INTERCHANGE SCHEDULE Standards in **Policy 3C, “Interchange – Schedule Standards.”**

**Reference only**

- 4.1.2. Operating reliability criteria.** BAs shall operate such that INTERCHANGE SCHEDULES or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria.

- 4.1.3. DC tie operator.** SENDING AND RECEIVING BAS shall coordinate with any DC tie operators on the SCHEDULING PATH.

**COVERED UNDER NERC V-0 STANDARD**

- 5. Maximum scheduled interchange.** The maximum NET INTERCHANGE SCHEDULE between two BAS shall not exceed the lesser of the following:
- 5.1. Total capacity of facilities.** The total capacity of both the owned and arranged-for transmission facilities in service for any transmission service provider along the path, or
  - 5.2. Total Transfer Capability.** The established network Total Transfer Capability (TTC) between BAs, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination*, NERC, June 1996.

## C. Interchange Schedule Standards

---

### **Standards**

- 1. INTERCHANGE SCHEDULE start and end time.** INTERCHANGE SCHEDULES shall begin and end at a time agreed to by the SOURCE AND SINK BAS, AND THE INTERMEDIARY BAS.

**COVERED UNDER NERC V-0 STANDARD**

- 2. Ramp start times.** BALANCING AUTHORITIES shall ramp the INTERCHANGE equally across the start and end times of the schedule.

- 3. Ramp duration.** BAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise:

**3.1 INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration.

**3.2 INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration.

**NAESB REQUIREMENT 14.0, 14.1, 14.2**

- 3.3 INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** The BAs that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.

**COVERED UNDER NERC V-0 STANDARD**

- 3.4 Exceptions for Compliance with Disturbance Control Standard and Line Load Relief.** 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, but must be identical for the SENDING AND RECEIVING BAS [See also Policy 1B, "Generation Control Performance – Disturbance Control Standard," Requirement 2 and subsections on contingency reserve.]

**COVERED UNDER NERC V-0 STANDARD**

- 4.0 INTERCHANGE SCHEDULE accounting.** Block accounting shall be used.

**NAESB REQUIREMENT 12.0**

## D. Interchange Transaction Modifications

---

### *Introduction*

This section specifies PURCHASING-SELLING ENTITY's, TRANSMISSION PROVIDER's, and Balancing Authorities' rights and requirements for modifying an INTERCHANGE TRANSACTION tag after it has been approved and implemented as described in the preceding sections.

### *Requirements*

1. **INTERCHANGE TRANSACTION modification for market-related issues.** The PURCHASING-SELLING ENTITY that submitted an INTERCHANGE TRANSACTION tag may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started. These modifications may be made due to changes in contracts, economic decisions, or other market-based influences. In cases where a market operator is serving as the source or sink for a TRANSACTION, then they shall have the right to effect changes to the energy flow as well (based on the results of the market clearing).

#### **NAESB REQUIREMENT 10.0**

- 1.1. **Increases.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be increased to reflect a desire to flow more energy or commit more transmission than originally requested. Necessary transmission must be either available from the earlier TRANSACTION or provided with the increase.
- 1.2. **Extensions.** The INTERCHANGE TRANSACTION tag's energy profile may be extended to reflect a desire to flow energy during hours not previously specified. Necessary transmission capacity must be provided with the extension.
- 1.3. **Reductions.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be reduced to reflect a desire to flow less energy or commit less transmission than originally requested. Reductions are used to indicate cancellations and terminations, as well as partial decreases.
- 1.4. **Combinations of 1.1, 1.2, and 1.3 may be submitted concurrently.**
- 1.5. **Coordination responsibilities of the PURCHASING-SELLING ENTITY.** The modification must be provided by the PURCHASING-SELLING ENTITY to the following INTERCHANGE TRANSACTION participants:
  - PURCHASING-SELLING ENTITIES
  - Balancing Authorities OR THEIR SCHEDULING AGENTS
  - TRANSMISSION SERVICE PROVIDERS
  - RELIABILITY AUTHORITIES
  - LOAD-SERVING ENTITIES
  - GENERATOR OWNERS
  - Security Analysis Services

FERC Orders 888, 889, 638, and a provider's OATT guide transmission requests. Tagging policy shall not supersede OASIS requirements.

#### **NAESB REQUIREMENT 10.0**

- 1.6 **INTERCHANGE TRANSACTION modification and evaluation time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Section D of **Appendix 3A1, “Tag Submission and Evaluation Timetable.”**

**NAESB REQUIREMENT 10.0**

2. **INTERCHANGE TRANSACTION modification for reliability-related issues.** A RELIABILITY AUTHORITY, TRANSMISSION PROVIDER, SOURCE OR SINK BA may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started. These modifications may be made *only* due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load.

**COVERED UNDER NERC V-0 STANDARD**

- 2.1. **Assignment of coordination responsibilities during TLR events.** At such times when TLR is required to ensure reliable operation of the electrical system, and the TLR requires holding or curtailing INTERCHANGE TRANSACTIONS, the SINK BA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. See **Policy 9, Appendix 9C1 “Transmission Loading Relief Procedure – Eastern Interconnection.”**

2.1.1. **Reductions.** When a RELIABILITY AUTHORITY must curtail or hold an INTERCHANGE TRANSACTION to respect TRANSMISSION SERVICE reservation priorities or to mitigate potential or actual OPERATING SECURITY LIMIT violations, the RELIABILITY AUTHORITY shall inform the Sink BA listed on the INTERCHANGE TRANSACTION tag of the greatest reliable level at which the affected INTERCHANGE TRANSACTION may flow.

2.1.2. **Reloads.** At such time as the TLR event allows for the reloading of the transaction, the RELIABILITY AUTHORITY shall inform the Sink BA listed on the INTERCHANGE TRANSACTION tag of the releasing of the INTERCHANGE TRANSACTION’S limit.

- 2.2. **Coordination when implementing other congestion management procedures.** As a part of some local and regional congestion management and transmission line overload procedures, the TRANSMISSION SERVICE PROVIDER or BALANCING AUTHORITY is responsible for implementing curtailment of INTERCHANGE TRANSACTIONS. The TRANSMISSION PROVIDER or affected BALANCING AUTHORITY may adjust the INTERCHANGE TRANSACTION tags as required to implement those local and regional congestion management or transmission overload relief procedures that have been approved by the Region(s) or NERC.

2.2.1. **Reductions.** When a TRANSMISSION PROVIDER or BALANCING AUTHORITY experiences the need to invoke a congestion management or transmission line overload procedure, it may use the curtailment feature of E-Tag to inform the Source and Sink BAs listed on the INTERCHANGE TRANSACTION tag of the greatest reliability limit at which the affected INTERCHANGE TRANSACTION may flow.

2.2.2. **Reloads.** At such time as the need for the congestion management or transmission line overload relief procedure allows for the full or partial reloading of the

transaction, the TRANSMISSION PROVIDER or BALANCING AUTHORITY may use the reload feature of E-Tag to inform the SOURCE AND SINK BA listed on the INTERCHANGE TRANSACTION tag that the INTERCHANGE TRANSACTION'S reliability limit has changed.

**2.3. Assignment of coordination responsibilities during a loss of generation.** At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS, the Source BA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

**2.3.1. Reductions.** When a generation operator experiences a full or partial loss of generation, it shall notify the HOST BA (the SOURCE BA for the INTERCHANGE TRANSACTION). The HOST BA contacts the PSE that is responsible for the generation. The PURCHASING-SELLING ENTITY providing Generation determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the PSE who submitted the tag, or directly if the entity is the PSE who submitted the tag or a market operator). If the PSE providing Generation does not resolve the condition, the HOST BA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the generation.

**2.3.2. Reloads.** Upon return of the generation, the generator operator shall notify the HOST BA (the SOURCE BA for the INTERCHANGE TRANSACTION). The HOST BA contacts the PSE that is responsible for the generation. The PURCHASING-SELLING ENTITY providing generation determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the PSE who submitted the tag, or directly if the entity is PSE who submitted the tag or a market operator). The HOST BA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the generation (but not override any market-based reductions).

**2.4. Assignment of coordination responsibilities during a loss of load.** At such times when a loss of load necessitates curtailing INTERCHANGE TRANSACTIONS, the Sink BA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

**2.4.1. Reductions.** When a LOAD-SERVING ENTITY experiences a loss of load, it shall notify its HOST BA (the SINK BA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (via either the PSE who submitted the tag, or directly if the entity is the PSE who submitted the tag or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST BA, the HOST BA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the load.

**2.4.2. Reloads.** Upon return of the load, THE LOAD-SERVING ENTITY shall notify its HOST BA (the SINK BA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via PSE who submitted the tag, or directly if the entity is PSE who submitted the tag or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST BA, the HOST BA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the load (but not override any market-based reductions).

**Covered under NERC V-0 Standard**

**2.5. Coordination responsibilities for reliability-related issues.** The modification must be provided by the requesting BALANCING AUTHORITY, TRANSMISSION PROVIDER, or RELIABILITY AUTHORITY to the following INTERCHANGE TRANSACTION participants:

- Purchasing Selling Entities
- Source OR SINK BA or their Scheduling Agent
- TRANSMISSION SERVICE PROVIDERS
- LOAD-SERVING ENTITY
- Security Analysis Services

**COVERED UNDER NERC V-0 STANDARD**

**2.6 INTERCHANGE TRANSACTION modification and evaluation time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Appendix 3A1, “Tag Submission and Evaluation Timetable”.

**COVERED UNDER NERC V-0 STANDARD**

# ~~Policy 5~~**Business Standard #\*\*\*\*\*** —

## **Emergency Operations**

Version 0 – Draft **21**

### ***Policy Subsections***

~~A. Operating Authority Responsibilities~~  
~~B. Communications and Coordination~~  
~~C. Capacity and Energy Emergencies~~  
~~D. Transmission~~  
~~E. System Restoration~~  
~~F. Disturbance Reporting~~  
~~G. Sabotage Reporting~~

### ***Introduction***

~~Operating emergencies on the BULK ELECTRIC SYSTEM may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, equipment damage, and interruption of customer service.~~

~~The integrity and reliability of the BULK ELECTRIC SYSTEM is of paramount importance, and will take precedence above all other aspects including commercial operations; therefore, all OPERATING AUTHORITIES and Reliability Authorities are expected to cooperate and take appropriate action to mitigate the severity or extent of any system emergency. NERC maintains Standards/Policies pertaining to the operation of the BULK ELECTRIC SYSTEM under emergency conditions. These Standards/Policies define the reliability considerations for the issuance of EMERGENCY EMERGENCY ALERTS. The purpose of the present NAESB Business Standard is to cover the commercial aspects of the operation of the BULK ELECTRIC SYSTEM under such emergency conditions once initiated as per the NERC applicable Standards/Policies.~~

### ***Terms***

~~**BURDEN.** Operation of the BULK ELECTRIC SYSTEM that violates or is expected to violate a SOL or IROL in the INTERCONNECTION or that violates any other NERC, Regional, or local operating reliability policies or standards.~~

1.

2.

3.

## **~~A. Responsibilities of Reliability Authorities, Balancing Authorities, and Transmission Operators~~**

---

### **~~Requirements~~**

**~~1. Operating within limits.~~** The RELIABILITY AUTHORITY and TRANSMISSION OPERATOR shall operate within the INTERCONNECTION RELIABILITY OPERATING LIMITS (IROLs) and SYSTEM OPERATING LIMITS (SOLs)

**~~2. RELIABILITY AUTHORITY, BALANCING AUTHORITY AND TRANSMISSION OPERATOR responsibility.~~** The RELIABILITY AUTHORITY, BALANCING AUTHORITY AND TRANSMISSION OPERATOR SHALL have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate operating emergencies.

**~~Mitigating emergencies.~~** The RELIABILITY AUTHORITY, BALANCING AUTHORITY, AND TRANSMISSION OPERATOR SHALL take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

**~~Complying with RELIABILITY directives.~~** The BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall comply with RELIABILITY AUTHORITY directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall immediately inform the RELIABILITY AUTHORITY of the inability to perform the directive so that the RELIABILITY AUTHORITY can implement alternate remedial actions.

~~2.2.1 The DISTRIBUTION PROVIDER will comply with all reliability directives issued by the TRANSMISSION OPERATOR~~

~~2.2.2 The LOAD SERVING ENTITY will assist the DISTRIBUTION PROVIDER under emergency conditions.~~

**~~3. Unknown operating states.~~** If the RELIABILITY AUTHORITY, BALANCING AUTHORITY, OR TRANSMISSION PROVIDER enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

**~~4. Information sharing.~~** To facilitate emergency assistance, the RELIABILITY AUTHORITY, BALANCING AUTHORITY, AND TRANSMISSION OPERATOR shall inform other potentially affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND TRANSMISSION OPERATORS of real time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency.

**~~5. Rendering assistance.~~** The RELIABILITY AUTHORITY, BALANCING AUTHORITY, AND TRANSMISSION OPERATOR shall render all available emergency assistance requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

~~5.1 The Distribution Provider and Load Serving Entity will assist as requested by the appropriate responsible entity~~



A. Operating Authority Responsibilities

---

~~6. Keeping facilities in service.~~ The RELIABILITY AUTHORITY OR TRANSMISSION OPERATOR shall not remove BULK ELECTRIC SYSTEM facilities from service if removing those facilities would BURDEN neighboring systems unless:

~~The RELIABILITY AUTHORITY OR TRANSMISSION OPERATOR first notifies the adjacent RELIABILITY AUTHORITY OR TRANSMISSION OPERATOR and coordinates the impact resulting from the removal of the BULK ELECTRIC SYSTEM facility or;~~

~~When time does not permit such notification and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the RELIABILITY AUTHORITY OR TRANSMISSION OPERATOR shall notify adjacent RELIABILITY AUTHORITIES at the earliest possible time to ensure OPERATING AUTHORITY coordination.~~

~~7. Remaining interconnected.~~ The RELIABILITY AUTHORITY AND TRANSMISSION OPERATOR shall make every effort to remain connected to the INTERCONNECTION. If the RELIABILITY AUTHORITY OR TRANSMISSION OPERATOR determines that by remaining interconnected, it is in imminent danger of violating System Operating Limits or Interconnected Reliability Operating Limits, the RELIABILITY AUTHORITY AND TRANSMISSION OPERATOR may take such actions, as it deems necessary, to protect its RESPONSIBLE AREA.

~~8. Complying with control performance standards.~~ The BALANCING AUTHORITY shall comply with Control Performance Standards and the Disturbance Control Standard [See Policy 1A, “Control Performance Standard”] during an emergency.

~~9. Coordinating interchange.~~ The BALANCING AUTHORITY AND TRANSMISSION PROVIDER shall coordinate INTERCHANGE SCHEDULE changes in accordance with Policy 3, “Interchange,” during an emergency.

~~10. Keeping automatic generation control in service.~~ Each BALANCING AUTHORITY shall maintain automatic generation control equipment operational and in service. [See Policy 1E, “Automatic Generation Control Standard”]

~~11. Taking immediate action.~~ The BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall immediately take action to restore the real and reactive power balance. If the BALANCING AUTHORITY AND TRANSMISSION OPERATOR is unable to restore its real and reactive power balance it shall request emergency assistance (from who). If corrective actions or emergency assistance is not adequate to mitigate the real and reactive power balance, then the RELIABILITY AUTHORITY, BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall implement firm load shedding.

~~12. Reducing the effects of power flows.~~ The RELIABILITY AUTHORITY AND TRANSMISSION OPERATOR shall immediately reduce the effects of power flows through other RELIABILITY AUTHORITY AND TRANSMISSION PROVIDER AREAS if those flows have been identified as contributing to an operating emergency (e.g., resulting in SOL or IROL violations) in those other RELIABILITY AUTHORITY AND TRANSMISSION PROVIDER AREAS.

## **~~B. Communications and Coordination~~**

---

~~[Appendix 7A – Instructions for Interregional Emergency Telephone Networks]~~

### **~~Requirements~~**

~~1. **Communications.** The BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall have communications (voice and data links) to appropriate RELIABILITY AUTHORITIES, BALANCING AUTHORITIES AND TRANSMISSION OPERATORS, which are staffed and available to act in addressing a real-time emergency condition.~~

~~2. **Notification.** The BALANCING AUTHORITY AND TRANSMISSION OPERATOR shall notify its RELIABILITY AUTHORITY and all other potentially affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND TRANSMISSION OPERATORS through predetermined communication paths of any condition that could threaten the reliability of its responsible AUTHORITY AREA.~~

~~**Using the Interconnection-wide telecommunications system.** When a condition is identified that could threaten the reliability of the INTERCONNECTION or when firm load shedding is anticipated, the affected BALANCING AUTHORITY OR TRANSMISSION OPERATOR, via its RELIABILITY AUTHORITY, shall utilize the INTERCONNECTION-wide telecommunications network in accordance with **Appendix 7A – Regional and Interregional Telecommunication, Subsection A, “NERC Hotline,”** to convey the following information to others in the INTERCONNECTION:~~

~~**Insufficient resources.** The BALANCING AUTHORITY is unable to purchase capacity or energy to meet its demand and reserve requirements on a day-ahead or hour-by-hour basis.~~

~~**IROL violation.** The RELIABILITY AUTHORITY recognizes that potential or actual line loadings, and voltage or reactive levels are such that a single CONTINGENCY could threaten the reliability of the INTERCONNECTION. (Once a single CONTINGENCY occurs, the RELIABILITY AUTHORITY shall prepare for the next CONTINGENCY.)~~

~~**Implementation of emergency actions.** The BALANCING AUTHORITY OR TRANSMISSION OPERATOR anticipates initiating a 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding for other than local problems.~~

~~**Sabotage incident.** The BALANCING AUTHORITY, TRANSMISSION PROVIDER, OR TRANSMISSION SERVICE PROVIDER suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.~~

~~**Protocols.** The RELIABILITY AUTHORITY shall issue directives in a clear, concise, definitive manner. The BALANCING AUTHORITY, TRANSMISSION OPERATOR, AND TRANSMISSION SERVICE PROVIDER shall receive a response from the person receiving the directive who will repeat the information given. All entities shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.~~

## ~~C. Capacity and Energy Emergencies~~

---

### ~~[Appendix 5C—Energy Emergency Alerts]~~

#### ***Introduction***

During a system emergency, the BALANCING AUTHORITY shall continue to comply with NERC Control Performance and Disturbance Control Standards as explained in Policy 1, “Generation Control and Performance,” regardless of costs. In other words, the BALANCING AUTHORITY may not rely on the frequency bias of the other BALANCING AUTHORITIES in the INTERCONNECTION to provide energy during the emergency because doing so reduces the INTERCONNECTION’S ability to recover its frequency following additional generator failures.

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

1. Requesting assistance from other BALANCING AUTHORITIES
2. Declaring an ENERGY EMERGENCY through its RELIABILITY AUTHORITY
3. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

#### **Requirements**

**1. Anticipating capacity or energy emergency.**

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

**2. Returning ACE to Acceptable Levels.**

In the event of a capacity or energy emergency, generation and transmission facilities shall be used to the fullest extent practicable to comply with the CPS and DCS as defined in Policy 1A, “Control Performance Standard.” Using bias variables to “cover up” energy emergency problems is prohibited. A BALANCING AUTHORITY shall utilize the following actions to the fullest extent practicable to return ACE to acceptable levels during an energy emergency:

**Mitigating an energy emergency.** Once the BALANCING AUTHORITY has exhausted the following steps:

Load ~~All~~all available generating capacity is loaded, ~~and~~

Utilize ~~All~~all operating reserve is utilized, ~~and~~

Interrupt ~~All~~all interruptible load and interruptible exports ~~have been interrupted, and~~

Utilize ~~All~~all emergency assistance from other BALANCING AUTHORITIES ~~is fully utilized, and~~

C. Insufficient Generating Capacity

**3. Failure to Return ACE to Acceptable Levels.**

A deficient BALANCING AUTHORITY that has failed to return its ACE to acceptable levels after having used all Requirement 2 actions to the fullest extent practicable shall initiate the following actions after a 15 minutes period:

~~Its ACE is negative and cannot be returned to zero in the next fifteen minutes, then~~

~~The BALANCING AUTHORITY shall m~~M~~anually shed firm load without delay to return its ACE to zero.~~

~~The deficient BALANCING AUTHORITY shall d~~D~~ecclare an EMERGENCY ENERGY Alert-ALERT in accordance with Appendix 5C-NERC applicable Standards/Policies.~~

~~Using INTERCONNECTION'S bias. The deficient BALANCING AUTHORITY may only use the assistance provided by the INTERCONNECTION'S frequency bias for the time needed to implement corrective actions.~~

**3.4. Elevating Transmission Service Priority within the Eastern INTERCONNECTION.**

~~When a~~A TRANSMISSION PROVIDER expects to~~shall elevate the transmission service priority of an INTERCHANGE TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) only if the following conditions are satisfied:~~

Such a process is permitted in its transmission tariff

The LOAD-SERVING ENTITY served by the BALANCING AUTHORITY or TRANSMISSION PROVIDER has requested its RELIABILITY AUTHORITY to initiate an ENERGY EMERGENCY ALERT

**5. Initiating an Energy Emergency Alerts-ENERGY EMERGENCY ALERT-.**

5.1 ENERGY EMERGENCY Alerts-ALERTS shall be initiated only by a RELIABILITY AUTHORITY-at

1) at the RELIABILITY AUTHORITIES own request or,

2) upon the request of a BALANCING AUTHORITY, or

3) upon the request of a LOAD SERVING ENTITY. These alerts shall be posted on the NERC Web site. [See Appendix 5C, "Energy Emergency Alerts"]

5.2 LOAD SERVING ENTITIES shall be allowed to request an ENERGY EMERGENCY ALERT for the following reasons only:

C. Insufficient Generating Capacity

The LOAD SERVING ENTITY is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or

The LOAD SERVING ENTITY cannot schedule its resources due to, for example, ATC limitations or Transmission Loading Relief limitations

5.3 LOAD SERVING ENTITIES shall not request ENERGY EMERGENCY ALERTS based upon the cost of available resources.

**6 Posting of ENERGY EMERGENCY ALERTS.**

The RELIABILITY AUTHORITY shall post the initiation of the ENERGY EMERGENCY ALERT and the expected total transmission service capacity in MW that will be subject to the Transmission Service Priority Elevation. The following steps shall be followed by the RELIABILITY AUTHORITY for posting:

6.1 Upon an ENERGY EMERGENCY ALERT Level 1 (EEA1), the RELIABILITY AUTHORITY shall post the *forecasted* Transmission Service change from Priority 6 to Priority 7

6.2 Upon an ENERGY EMERGENCY ALERT Level 2 (EEA2), the RELIABILITY AUTHORITY shall post an *announcement* of the Transmission Service change from Priority 6 to Priority 7

~~EEA 1 will be used to alert that available resources are in use.~~

~~EEA 2 will be used to alert that load management procedures are in effect. *announce* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.~~

~~EEA 3 will be used to alert that firm load interruption is eminent or in progress.~~

~~EEA 0 will be used to alert a state of termination~~

~~**5.Unilateral action.** The BALANCING AUTHORITY shall not unilaterally adjust generation in an attempt to return INTERCONNECTION frequency to normal beyond that supplied through frequency bias action and INTERCHANGE SCHEDULE changes. Such unilateral adjustment may overload transmission facilities.~~

## **D. Transmission**

---

### **Introduction**

This policy:

1. Summarizes the authority, information and tools required by OPERATING AUTHORITIES responsible for the reliability of the INTERCONNECTIONS.
2. Identifies the accountability for developing and implementing procedures to alleviate SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL) violations.
3. Describes the requirement to develop procedures for the curtailment and restoration of transmission service.

### **Requirements**

1. ~~Mitigating SOL and IROL violations.~~ The ~~RELIABILITY AUTHORITY AND TRANSMISSION OPERATOR~~ experiencing or contributing to an SOL or IROL violation shall take immediate steps to relieve the condition, which may include firm load shedding.
2. ~~BALANCING AUTHORITIES and Transmission Operators shall not BURDEN others.~~ The Balancing Authority and Transmission Operator shall ensure they operate to prevent the likelihood that a disturbance, action, or non-action will result in a SOL or IROL violation in its OPERATING AUTHORITY AREA or another area of the INTERCONNECTION. In instances where there is a difference in derived operating limits, the BULK ELECTRIC SYSTEM shall always be operated to the most limiting parameter.
3. The ~~BALANCING AUTHORITY OR TRANSMISSION OPERATOR~~ shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered.
4. Neighboring ~~RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND TRANSMISSION OPERATORS~~ impacted by the disconnection shall be notified prior to switching, if time permits, otherwise, immediately thereafter.
5. The ~~TRANSMISSION OPERATOR~~ shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The ~~TRANSMISSION OPERATOR~~ shall use the results of these analyses to immediately mitigate the SOL violation.

## **~~E. System Restoration~~**

---

~~[Policy 6D—Operations Planning—System Restoration]  
[Electric System Restoration Reference Document]~~

### ***Introduction***

~~After a system collapse, restoration shall begin when the RELIABILITY AUTHORITY and its affected OPERATING AUTHORITY(IES) determine that they can proceed in an orderly and secure manner. RELIABILITY AUTHORITIES and affected OPERATING AUTHORITIES shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, OPERATING AUTHORITIES shall avoid premature action to prevent a re-collapse of the BULK ELECTRIC SYSTEM.~~

~~Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation shall remain in balance at normal frequency as the BULK ELECTRIC SYSTEM is restored.~~

### ***Requirements***

~~1. **Returning to normal operations.** Following a disturbance in which one or more RELIABILITY AUTHORITY AREAS or Balancing Authority Areas become isolated, steps shall begin immediately to return the BULK ELECTRIC SYSTEM to normal:~~

~~**Extent of isolated BULK ELECTRIC SYSTEM.** The RELIABILITY AUTHORITY working in conjunction with its Balancing Authorities, Transmission Operators, and Transmission Service Providers AUTHORITY shall determine the extent and condition of the isolated area(s).~~

~~**Frequency restoration.** The RELIABILITY AUTHORITY shall then take the necessary action to restore BULK ELECTRIC SYSTEM frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.~~

~~**INTERCHANGE SCHEDULE review.** The RELIABILITY AUTHORITY and affected BALANCING AUTHORITIES shall immediately review the INTERCHANGE SCHEDULES between those BALANCING AUTHORITIES or fragments of those BALANCING AUTHORITIES 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.~~

~~**Desynchronizing.** When voltage, frequency, and phase angle permit, the TRANSMISSION OPERATOR may resynchronize the isolated area(s) with the surrounding area(s), upon notifying its RELIABILITY AUTHORITY and adjacent Transmission Operators, and considering the size of the area being reconnected and the capacity of the transmission lines effecting the reconnection. (The Transmission Operators restoration plan should consider the number of synchronizing points across the system.)~~

~~**Off-site supply for nuclear plants.** The TRANSMISSION OPERATOR shall give high priority to restoration of off-site power to nuclear stations.~~

~~**Load Shedding.** Load shall be shed in neighboring Reliability Authorities or Balancing Authorities areas, where required, to permit successful interconnected system restoration.~~

## **F. ~~Disturbance Reporting~~**

---

### **[Appendix 5F—Reporting Requirements for Major Electric System Emergencies]**

#### ***Introduction***

Disturbances or unusual occurrences that jeopardize the operation of the BULK ELECTRIC SYSTEM, and result, or could result, in system equipment damage, or customer interruptions, shall be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to RELIABILITY AUTHORITIES, OPERATING AUTHORITIES, TRANSMISSION OPERATORS, Regional Councils, NERC, and regulatory agencies entitled to the information.

#### ***Requirements***

- 1. ~~Regional Council Reporting Procedures.~~** Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
- 2. ~~Analyzing disturbances.~~** BULK ELECTRIC SYSTEM disturbances shall be promptly analyzed by the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS.
- 3. ~~Disturbance reports.~~** Based on the NERC and DOE disturbance reporting requirements, those RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND TRANSMISSION OPERATORS responsible for investigating the incident shall provide a preliminary written report to their Regional Council and NERC.

**~~Preliminary written reports.~~** Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnected Reliability Operating Limit and Preliminary Disturbance Report form shall be submitted by the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS within 24 hours of the disturbance or unusual occurrence. Certain events (e.g. near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.

**~~Preliminary reporting during adverse conditions.~~** Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnected Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS shall notify its Regional Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

**~~Final written reports.~~** If in the judgment of the Regional Council, after consultation with the RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS in which a disturbance occurred, a final report is required, the affected RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Council approval.



F. Disturbance Reporting

---

- ~~4. **Notifying NERC.** The NERC Disturbance Reporting Requirements, shown in **Appendix 5F, Sections A and B**, are the minimum requirements for reporting disturbances, unusual occurrences, and voltage excursions to NERC.~~
- ~~5. **Notifying DOE.** The U.S. Department of Energy's most recent Emergency Incident and Disturbance Reporting Requirements, outlined in **Appendix 5F, Section C**, are the minimum requirements for U.S. utilities and other entities subject to Section 13(b) of the Federal Energy Administration Act of 1974. Copies of these reports shall be submitted to NERC at the same time they are submitted to DOE.~~
- ~~6. **Assistance from NERC Operating Committee (OC) and the Disturbance Analysis Working Group (DAWG).** When a BULK ELECTRIC SYSTEM disturbance occurs, the Regional Council's OC and DAWG representatives shall make themselves available to the RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.~~
- ~~7. **Final report recommendations.** The Regional Council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Council shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.~~

## **G. Sabotage Reporting**

---

### **Introduction**

Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

### **Requirements**

1. **Recognizing sabotage.** Each RELIABILITY AUTHORITY, BALANCING AUTHORITY, AND SYSTEM OPERATOR shall have procedures for the recognition of and for making its SYSTEM OPERATORS aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the INTERCONNECTION. Procedures shall also be established for the communication of information concerning sabotage events to other RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS in the INTERCONNECTION.
2. **Reporting guidelines.** SYSTEM OPERATORS shall be provided with guidelines including lists of utility contact personnel, for reporting disturbances due to sabotage events.
3. **Contact with FBI and RCMP.** RELIABILITY AUTHORITIES, BALANCING AUTHORITIES, AND SYSTEM OPERATORS shall establish communications contacts with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

### **Guides**

- 1.

# Business Standard

## Emergency Operations

---

Version 0 – Draft 1

### ***Introduction***

NERC maintains Standards pertaining to the operation of the BULK ELECTRIC SYSTEM under emergency conditions. These NERC Standards define the reliability considerations for the issuance of ENERGY EMERGENCY ALERTS. The purpose of this NAESB Business Practice Standard is to cover the commercial aspects of the operation of the BULK ELECTRIC SYSTEM under such emergency conditions once initiated as per the NERC applicable Standards.

### ***Requirements***

#### **1. Anticipating capacity or energy emergency.**

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

#### **2. Returning ACE to Acceptable Levels.**

A BALANCING AUTHORITY shall utilize the following actions to the fullest extent practicable to return ACE to acceptable levels during an energy emergency:

- Load all available generating capacity
- Utilize all operating reserve
- Interrupt all interruptible load and interruptible exports
- Utilize all emergency assistance from other BALANCING AUTHORITIES

#### **3. Failure to Return ACE to Acceptable Levels.**

A deficient BALANCING AUTHORITY that has failed to return its ACE to acceptable levels after having used all Requirement 2 actions to the fullest extent practicable shall initiate the following actions after a 15 minute period:

- Manually shed firm load without delay to return its ACE to zero.
- Declare an EMERGENCY ENERGY ALERT in accordance with NERC applicable Standards.

**4. Elevating Transmission Service Priority within the Eastern INTERCONNECTION.**

A TRANSMISSION PROVIDER shall elevate the transmission service priority of an INTERCHANGE TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) only if the following conditions are satisfied:

- Such a process is permitted in its transmission tariff
- The LOAD-SERVING ENTITY served by the BALANCING AUTHORITY or TRANSMISSION PROVIDER has requested its RELIABILITY AUTHORITY to initiate an ENERGY EMERGENCY ALERT

**5. Initiating an ENERGY EMERGENCY ALERT.**

5.1 ENERGY EMERGENCY ALERTS shall be initiated only by a RELIABILITY AUTHORITY for the following reasons only:

- upon the RELIABILITY AUTHORITY'S own request
- upon the request of a BALANCING AUTHORITY
- upon the request of a LOAD SERVING ENTITY

5.2 LOAD SERVING ENTITIES shall be allowed to request an ENERGY EMERGENCY ALERT for the following reasons only:

- The LOAD SERVING ENTITY is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase
- The LOAD SERVING ENTITY cannot schedule its resources due to, for example, ATC limitations or Transmission Loading Relief limitations

5.3 RELIABILITY AUTHORITIES , BALANCING AUTHORITIES and/or LOAD SERVING ENTITIES shall not request ENERGY EMERGENCY ALERTS based upon cost.

**6. Posting of ENERGY EMERGENCY ALERTS.**

The RELIABILITY AUTHORITY shall post on the NERC web site the initiation of the ENERGY EMERGENCY ALERT and the expected total transmission service capacity in MW that will be subject to the Transmission Service Priority Elevation. The following steps shall be followed by the RELIABILITY AUTHORITY for posting:

6.1 Upon an ENERGY EMERGENCY ALERT Level 1 (EEA1), the RELIABILITY AUTHORITY shall post the *forecasted* Transmission Service change from Priority 6 to Priority 7

- 6.2 Upon an ENERGY EMERGENCY ALERT Level 2 (EEA2), the RELIABILITY AUTHORITY shall post an *announcement* of the Transmission Service change from Priority 6 to Priority 7

# NAESB Transmission Loading Relief Standard

Version 0

## Introduction

This standard defines procedures for curtailment and reloading of **INTERCHANGE TRANSACTIONS** to relieve overloads on the transmission grid. This process is defined in the requirements below, is depicted in Appendix A, and examples of curtailment calculations using these procedures are in Appendix B.

This standard only applies to the **EASTERN INTERCONNECTION**.

## 1. Requirements

- 1.1. **Initiation only by RELIABILITY AUTHORITY.** A RELIABILITY AUTHORITY shall be the only entity authorized to initiate the NAESB Transmission Loading Relief Procedure and shall do so at 1) the RELIABILITY AUTHORITY'S own request, or 2) upon the request of a TRANSMISSION OPERATOR.
- 1.2. **Mitigating transmission constraints.** A RELIABILITY AUTHORITY may utilize the TLR Procedure to mitigate potential or actual SYSTEM OPERATING LIMIT VIOLATIONS or INTERCONNECTION RELIABILITY OPERATING LIMIT violations on any transmission facility modeled in the INTERCHANGE DISTRIBUTION CALCULATOR (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 AUTHORITY.
    - 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 AUTHORITY shall not be required to follow the TLR Levels in their numerical order (**Requirement 2, "TLR Levels"**). Furthermore, if a RELIABILITY AUTHORITY deems that a transmission loading condition could jeopardize bulk system reliability, the RELIABILITY AUTHORITY shall have the authority to enter TLR Level 6 directly, and immediately direct the BALANCING AUTHORITIES or TRANSMISSION OPERATORS to take such actions as re-dispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing the TLR Transaction Curtailment Procedures, or other methods, to return the system to a secure state.
- 1.4. **Notification of TLR Procedure implementation.** The RELIABILITY AUTHORITY initiating the use of the TLR Procedure shall notify other RELIABILITY AUTHORITIES 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 AUTHORITIES.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall inform all other RELIABILITY AUTHORITIES via the RELIABILITY AUTHORITY Information System (RAIS) that the TLR Procedure has been implemented.

- 1.4.1.1. Actions expected.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall indicate the actions expected to be taken by other RELIABILITY AUTHORITIES.
  - 1.4.2. Notifying TRANSMISSION OPERATORS and BALANCING AUTHORITIES.** RELIABILITY AUTHORITIES shall notify TRANSMISSION OPERATORS and BALANCING AUTHORITIES in his RELIABILITY AREA when entering and leaving any TLR level.
  - 1.4.3. Notifying BALANCING AUTHORITIES.** The RELIABILITY AUTHORITY for the SINK BALANCING AUTHORITY shall be responsible for directing the sink BALANCING AUTHORITY to curtail the INTERCHANGE TRANSACTIONS as specified by the RELIABILITY AUTHORITY 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 AUTHORITY implementing the TLR Procedure shall update all other RELIABILITY AUTHORITIES (via the RAIS). TRANSMISSION OPERATORS and BALANCING AUTHORITIES who have had Interchange Transactions impacted by the TLR will be updated by their RELIABILITY AUTHORITY.
- 1.5. Obligations.** All RELIABILITY AUTHORITIES shall comply with the request of the RELIABILITY AUTHORITY who initiated the TLR Procedure, unless the initiating RELIABILITY AUTHORITY agrees otherwise.
  - 1.5.1. Use of TLR Procedure with “local” procedures.** A RELIABILITY AUTHORITY shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the RELIABILITY AUTHORITY shall be obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY AUTHORITY desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, he may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.<sup>1</sup>
- 1.6. Consideration of Interchange Transactions.** The administration of the TLR Procedure shall be guided by information obtained from the IDC (IDC).
  - 1.6.1. Interchange Transactions not in the IDC.** RELIABILITY AUTHORITIES 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 AUTHORITY is faced with an overload on a transmission element that is not modeled in the IDC, the RELIABILITY AUTHORITY shall use the best information available to curtail

---

<sup>1</sup> Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local re-dispatch procedure.

INTERCHANGE TRANSACTIONS in order to operate the system in a reliable manner. The RELIABILITY AUTHORITY shall use his 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 AUTHORITY (or TRANSMISSION OPERATOR through his RELIABILITY AUTHORITY) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use his best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating RELIABILITY AUTHORITY. 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 AUTHORITIES are involved in the TLR event, all impacted RELIABILITY AUTHORITIES shall be in agreement before any adjustments to the curtailment list are made.

**1.6.4. Curtailment that would cause a constraint elsewhere.** The RELIABILITY AUTHORITY shall be allowed to exempt an INTERCHANGE TRANSACTION from curtailment if the RELIABILITY AUTHORITY is aware that the INTERCHANGE TRANSACTION curtailment directed by the IDC would cause a constraint to occur elsewhere if the RELIABILITY AUTHORITY has consulted with those RELIABILITY AUTHORITIES who initiated the curtailment.

**1.6.5. Re-dispatch options.** The RELIABILITY AUTHORITY shall ensure that INTERCHANGE TRANSACTIONS that are linked to re-dispatch options are protected from curtailment in accordance with the re-dispatch provisions.

**1.6.6. Reallocation.** The RELIABILITY AUTHORITY shall consider for Reallocation any TRANSACTIONS of higher priority that meet the Approved-tag Submission Deadline during a TLR Level 3A. The RELIABILITY AUTHORITY shall consider for Reallocation any TRANSACTION using Firm Transmission Service that has met the Approved-tag Submission Deadline during a TLR Level 5A,

**1.9. IDC updates.** Any INTERCHANGE TRANSACTION adjustments or curtailments that result from using this Procedure must be entered into the IDC.

**1.10. Logging.** The RELIABILITY AUTHORITY shall complete the NERC Transmission Loading Relief Procedure Log whenever he invokes TLR Level 2 or above, and send a copy of the log via e-mail to NERC within two business days of the TLR event for posting on the NERC web site. See Appendix C.



- 1.11. TLR Event Review.** The RELIABILITY AUTHORITY 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 AUTHORITY’S RELIABILITY AREA, and all other RELIABILITY AUTHORITIES, including TRANSMISSION OPERATORS and BALANCING AUTHORITIES within their respective RELIABILITY AREAS, shall provide information, as requested by the initiating RELIABILITY AUTHORITY, 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 AUTHORITY 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 AUTHORITIES of potential SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violations.**
- 2.1.1.** The RELIABILITY AUTHORITY shall use following circumstances to establish the need for TLR Level 1:
- The transmission system is secure.
  - The RELIABILITY AUTHORITY foresees a transmission or generation contingency or other operating problem within his RELIABILITY AREA that could cause one or more transmission facilities to approach or exceed their **SYSTEM OPERATING LIMIT** or **INTERCONNECTION RELIABILITY OPERATING LIMIT**.
- 2.1.2. Notification procedures.** The RELIABILITY AUTHORITY shall notify all RELIABILITY AUTHORITIES via the Reliability Authority Information System as soon as the condition is foreseen. All affected RELIABILITY AUTHORITIES shall check to ensure that INTERCHANGE TRANSACTIONS are posted in the IDC.

**2.2. TLR Level 2 – Hold transfers at present level to prevent SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violations**

**2.2.1.** The RELIABILITY AUTHORITY shall use 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.

**2.2.2. Holding procedures.** The RELIABILITY AUTHORITY shall be allowed to hold the implementation of any additional INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD. However, the RELIABILITY AUTHORITY 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 AUTHORITY 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 AUTHORITY shall use 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT
- 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 AUTHORITY 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 **Requirement 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 **Requirement 6. “Interchange Transaction Reallocation During TLR Level 3a and 5a.”**

**2.3.2.1.** The RELIABILITY AUTHORITY 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 AUTHORITY 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 AUTHORITY shall proceed to TLR Level 5a.

**2.3.2.4.** The RELIABILITY AUTHORITY 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 to the Tag Authority 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 AUTHORITY shall fill available transmission capability by reloading or starting eligible TRANSACTIONS on a pro-rata basis.

**2.3.2.6.** The RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation**

**2.4.1.** The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering TLR Level 3b:

- One or more transmission facilities are operating above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken, or

- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT OR INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITY 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 SYSTEM OPERATING LIMIT OR INTERCONNECTION RELIABILITY OPERATING LIMIT Violation. The RELIABILITY AUTHORITY 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 **Requirement 7. “Interchange Transaction Curtailments During TLR Level 3b.”**

**2.4.3. Curtailment procedures to mitigate an SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.** The RELIABILITY AUTHORITY shall curtail INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD as specified in **Requirement 3. “Interchange Transaction Curtailment Order.”**

## **2.5. TLR Level 4 – Reconfigure Transmission**

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

- One or more Transmission Facilities are above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken

**2.5.2. Holding new INTERCHANGE TRANSACTIONS.** The RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation. The RELIABILITY AUTHORITY shall allow INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC by 00:25 or the time at which the TLR Level 4 is called, whichever is later.

**2.5.3. Reconfiguration procedures.** Following the curtailment of all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD in Level 3b that impact the CONSTRAINED FACILITIES, if a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation is imminent or occurring, the RELIABILITY AUTHORITY(IES) 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 **Requirement 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 AUTHORITY shall use following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure
- One or more transmission facilities are at their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT
- 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITY 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 re-dispatch options.** The RELIABILITY AUTHORITY shall assist the TRANSMISSION OPERATOR(s) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY AUTHORITY shall proceed to implement these options while proceeding to Steps 2 and 3 below.

**2.6.2.2. Step 2 –** The RELIABILITY AUTHORITY 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 **Requirement 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 AUTHORITY 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 **Requirement 6, “Interchange Transaction Reallocation During TLR 3a and 5a.”** The RELIABILITY AUTHORITY 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 re-dispatch options will continue to be implemented.

**2.7. TLR Level 5b – Curtail INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation.**

**2.7.1.** The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering TLR Level 5b:

- One or more Transmission Facilities are operating above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent, or
- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITY 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 re-dispatch options.** The RELIABILITY AUTHORITY shall assist the TRANSMISSION OPERATORS(S) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY AUTHORITY shall proceed to implement these options while proceeding to Steps 2 and 3 below.

**2.7.2.2. Step 2 –** The RELIABILITY AUTHORITY 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 **Requirement 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 AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation has been mitigated. The RELIABILITY AUTHORITY 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 re-dispatch options will continue to be implemented.

## **2.8. TLR Level 6 – Emergency Procedures**

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

- One or more Transmission Facilities are above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.
- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT upon the removal from service of a generating unit or another transmission facility.

**2.8.2. Implementing emergency procedures.** If the RELIABILITY AUTHORITY deems that SOL or IROL violations are imminent, the RELIABILITY AUTHORITY shall immediately direct the BALANCING AUTHORITIES and TRANSMISSION OPERATORS in his RELIABILITY AREA to re-dispatch 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 AUTHORITY.

## **2.9. TLR Level 0 – TLR concluded**

**2.9.1. Interchange TRANSACTION restoration and notification procedures.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall notify all RELIABILITY AUTHORITIES within the INTERCONNECTION via the RAIS when the SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violations are mitigated and the system is in a “normal” state, allowing INTERCHANGE TRANSACTIONS to be reestablished at his discretion. Those with the highest transmission priorities shall be reestablished first if possible.

# **3. Interchange Transaction Curtailment Order**

---

## **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. Hourly Service – NH

Priority 3. Daily Service – ND

Priority 4. Weekly Service – NW

Priority 5. 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 AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation.

### 3.3. ***Curtailment of Interchange Transactions Using Firm Transmission Service***

- 3.3.1. The RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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**

---

### ***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 RELIABILITY AUTHORITIES must agree on how the NERC Transmission Loading Relief Procedure will handle these INTERCHANGE TRANSACTIONS to, first, ensure the operational security of the INTERCONNECTION and, second, respect the obligations of the TRANSMISSION PROVIDERS’ tariffs.



The curtailment priority of an INTERCHANGE TRANSACTION depends on whether the CONSTRAINED FACILITY is on or off the contract path, and, if on the contract path, the Transmission Service of the link with the CONSTRAINED FACILITY.

The RELIABILITY AUTHORITY must also consider 1) the tariff obligations of the Transmission Provider with the CONSTRAINED FACILITY, 2) the Transmission Customer's re-dispatch or other congestion management arrangements, and 3) arrangements among the TRANSMISSION PROVIDERS for handling certain CONSTRAINTS. (Refer to Examples in Appendix G)

#### **4.1. Constraints ON the Contract Path**

- 4.1.1.** The RELIABILITY AUTHORITY initiating TLR shall consider the entire INTERCHANGE TRANSACTION non-firm if the transmission link 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.

**4.1.1.1. Discussion.** The TRANSMISSION OPERATOR simply has to call its RELIABILITY AUTHORITY, 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 AUTHORITY 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.

**4.1.2.1. 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 AUTHORITY 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.

**4.2.1.1. 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 AUTHORITY 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.

**4.2.2.1. 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 AUTHORITY 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**

---

### ***Introduction***

The provision of Point-to-Point (PTP) transmission service, Network Integration (NI) transmission service and service to Native Load (NL) 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 Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using Non-firm PTP 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 PTP transmission service, NI transmission service and service to NL (TLR Level 5a and 5b). Curtailment of Firm PTP transmission service shall be accompanied by the comparable curtailment of NI transmission service and service to NL 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 NL of each BALANCING AUTHORITY (BA). The following requirements are necessary to assure comparable REALLOCATION or CURTAILMENT of firm transmission service:

- 5.1.1.** The RELIABILITY AUTHORITY initiating a curtailment shall identify for curtailment all firm transmission services (i.e. PTP, NI and service to NL) 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 PTP transmission services, the TRANSFER DISTRIBUTION FACTORS (TDFs) must be greater than or equal to the CURTAILMENT THRESHOLD.
- 5.1.3.** For NI transmission service and service to NL, the generator-to-load distribution factors (GLDFs) must be greater than or equal to the CURTAILMENT THRESHOLD. The GLDF on a specific CONSTRAINED FACILITY for a given generator within a BALANCING AUTHORITY is defined as the generator's contribution to the flow on that flowgate when supplying the load of that BALANCING AUTHORITY.
- 5.1.4.** The Per Generator Method shall assign the amount of CONSTRAINED FACILITY relief that must be achieved by each BALANCING AUTHORITY'S NI transmission service or service to NL. 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 NI transmission service or service to NL 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 LSFs shall be defined as a general scaling of the native load within each BALANCING AUTHORITY. The Generator to Load Distribution Factor (GLDF) shall be calculated as the GSF minus the LSF. The IDC shall report all generators assigned to native load for which the GLDF is greater than or equal to the CURTAILMENT THRESHOLD. (REFER TO APPENDIX D FOR CALCULATION METHOD EXAMPLES)

## **6. Interchange Transaction Reallocation During TLR Levels 3a and 5a**

## Introduction

This standard 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 AUTHORITIES 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 built upon the premises of FERC Order 888, NERC Operating Policies and current business practices. Specifically, the key requirements are:

- 6.1.1.** When identifying transactions for REALLOCATION the RELIABILITY AUTHORITY 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 AUTHORITY 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 AUTHORITY 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 AUTHORITY 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 AUTHORITY shall reload curtailed INTERCHANGE TRANSACTIONS prior to starting new or increasing existing INTERCHANGE TRANSACTIONS.
- 6.1.6.** INTERCHANGE TRANSACTIONS whose tags were submitted to the Tag Authority 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 **Requirement 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 AUTHORITY 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 **Requirement 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 will 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.

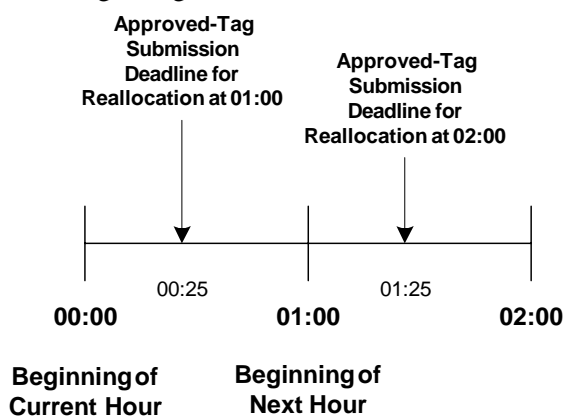
It should be noted that calling a TLR 3a does not necessarily mean that INTERCHANGE TRANSACTIONS using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the Approved-Tag Submission Deadline for Reallocation requirements and allow for a coordinated 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.

- 6.2.2. **Approved-Tag Submission Deadline for Reallocation.** RELIABILITY AUTHORITIES 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.



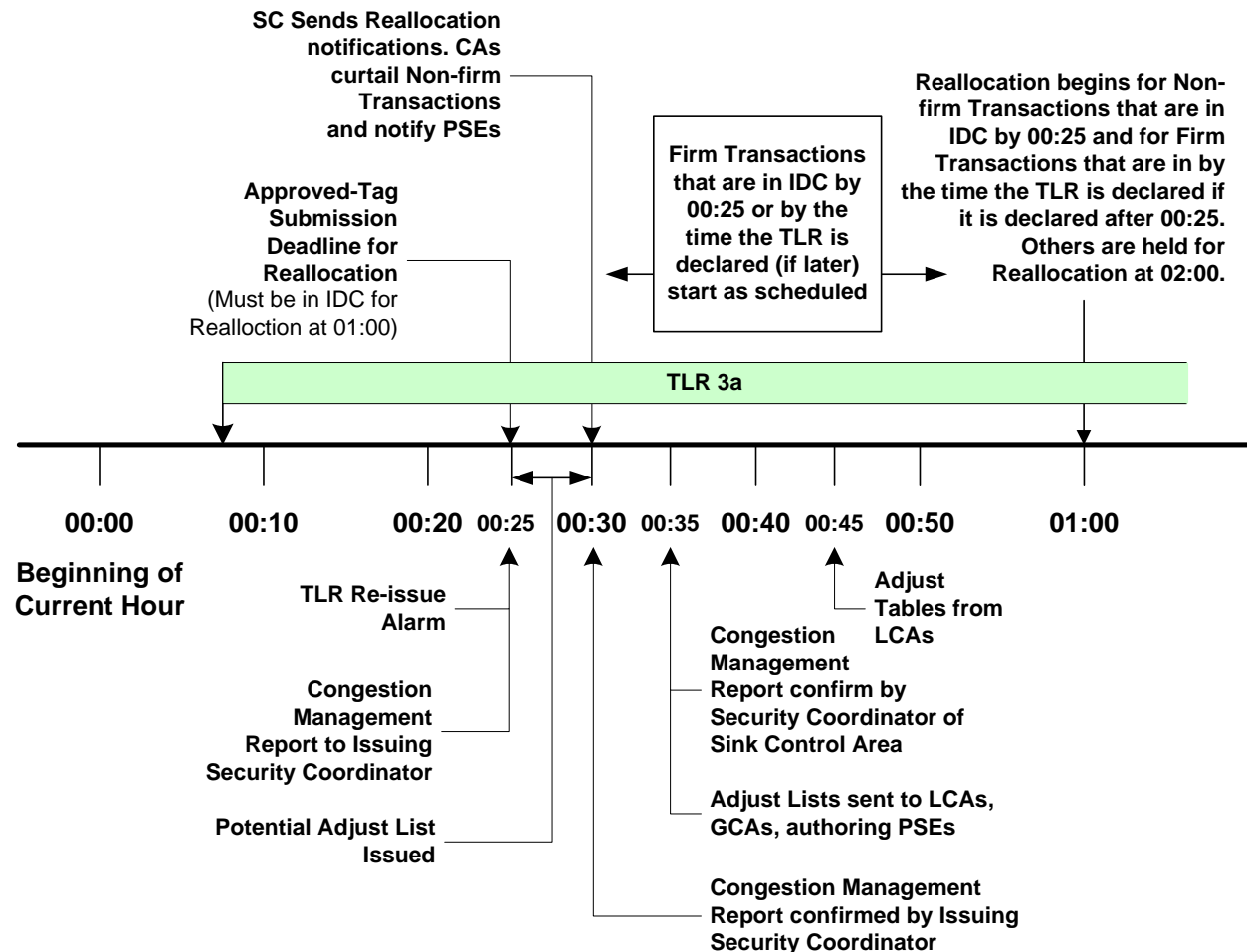
**Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation**

- 6.2.2.1. RELIABILITY AUTHORITIES shall consider all approved tags submitted to the IDC beyond these deadlines (for both Firm and Non-firm Point-to-

Point Transmission Service), which will not be allowed to start or increase at 01:00, but will be considered for REALLOCATION at 02:00.

**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.

**Figure 2 - Reallocation timing for TLR 3a called at 00:08.**



**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 (via the Tag Approval) by 00:25.

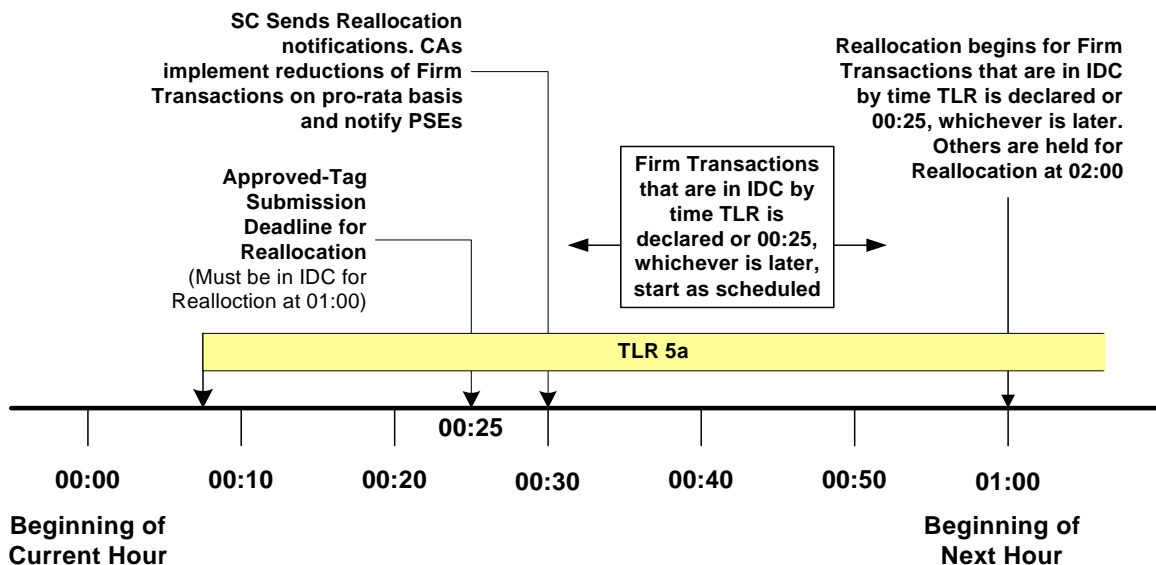
**6.2.5. Collective Scheduling Assessment Period.** At 00:25, the initiating RELIABILITY AUTHORITY (the one who called and still has a TLR 3a or 5a in effect) shall run the IDC to obtain a three-part list of INTERCHANGE TRANSACTIONS including their transaction status:

**6.2.5.1.** INTERCHANGE TRANSACTIONS that may start, increase, or reload shall have a status of PROCEED,

**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<sup>2</sup> and be considered for REALLOCATION at 02:00. Also, INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service submitted to the Tag Authority 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 AUTHORITY shall communicate the list to the appropriate sink RELIABILITY AUTHORITIES 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 AUTHORITY to input the necessary information (i.e., maximum flowgate loading and curtailment requirement) into the IDC by 00:25.

<sup>2</sup> The use of PROCEED, CURTAILED, and HOLD refer to an Interchange Transaction status in the IDC, not the E-tag status.

- 6.2.5.5.** Subsequent required reports before 01:00 shall allow the RELIABILITY AUTHORITIES 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.**

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 AUTHORITY shall have an option to specify the maximum loading of the CONSTRAINED FACILITY by all INTERCHANGE TRANSACTIONS using Point-to-Point Transmission Service. This allows the RELIABILITY AUTHORITY to take into consideration SYSTEM OPERATING LIMITS or INTERCONNECTION RELIABILITY OPERATING LIMITS and changes in TRANSACTIONS using other than point-to-point service taken under the OATT. 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITIES via an IDC Report. The RELIABILITY AUTHORITIES 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 site are contained in Appendix E.

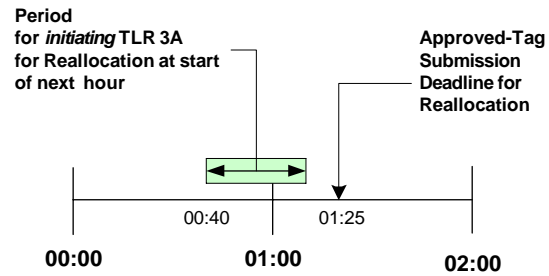
- 6.2.6. Customer Preferences on Timing to Call TLR 3a or 5a.** RELIABILITY AUTHORITIES shall leave a TLR 2 and call a TLR 3a as soon as possible (but no later than 30 minutes) to initiate the Approved-Tag Submission Deadline and start reallocating TRANSACTIONS. Nevertheless, recognizing the Approved-Tag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

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 AUTHORITY 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 AUTHORITY'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 standard provides the details for implementing TLR Level 3b, which curtails INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to assist the RELIABILITY AUTHORITY to recover from SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violations.

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

### Basic Requirements

- 7.1. The RELIABILITY AUTHORITY shall be allowed to call a TLR 3b at any time to help mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation.
- 7.2. The RELIABILITY AUTHORITY shall consider only those INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD for curtailment, holding, or halting.
- 7.3. The RELIABILITY AUTHORITY shall curtail existing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service as necessary to provide the required relief on the CONSTRAINED FACILITY.
- 7.4. The RELIABILITY AUTHORITY 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 AUTHORITY shall not allow existing INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are not curtailed to increase (they may flow at the same or reduced level).
- 7.6. The RELIABILITY AUTHORITY shall not reallocate INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service during a TLR 3b.

- 7.7.** The RELIABILITY AUTHORITY shall allow INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to start as explained in Appendix F, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”
- 7.8.** The RELIABILITY AUTHORITY shall progress to TLR Level 5b as necessary if there is still insufficient transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled after all Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed.
- 7.9.** The IDC shall issue ADJUST Lists to the Generation and Load Control Areas and the PURCHASING-SELLING ENTITY who submitted the tag. The ADJUST List will include:
  - 7.9.1.** INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are to be curtailed, halted, or held during current and next hours.
  - 7.9.2.** INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in Appendix F).
- 7.10.** The SINK BALANCING AUTHORITY shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.
- 7.11.** The RELIABILITY AUTHORITY shall be allowed to call a TLR Level 3a as soon as the SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation has been mitigated.
  - 7.11.1.** If the TLR Level 3a is called before the hour 01, then a Reallocation shall be computed for the start of that hour.
  - 7.11.2.** Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).

## **Appendices for NAESB Transmission Loading Relief Standard**

**Appendix A. Transaction Management and Curtailment Process**

**Appendix B. Transaction Curtailment Formula**

**Appendix C. Sample NERC Transmission Loading Relief Procedure Log**

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

**Appendix E. How the IDC Handles Reallocation**

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

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

---



## Appendix B Transaction Curtailment Formula

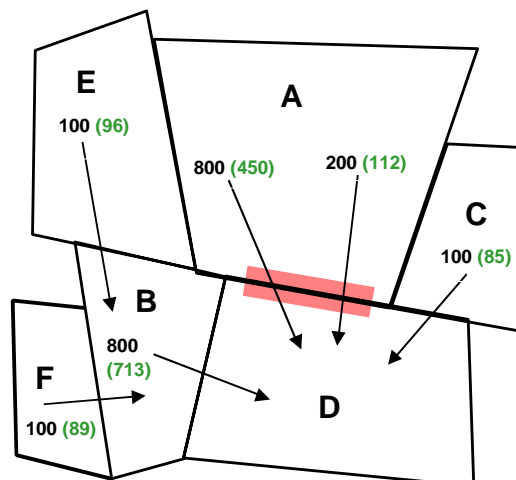
---

### ***Example***

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

<b>Column</b>	<b>Description</b>
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 we need 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 <i>contribute</i> to achieve the total reduction.
7. Transaction Reduction	Now we have to divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result we 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
<b>Example 1</b>									
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
	<b>2100</b>	<b>1.75</b>	<b>760</b>		<b>219.71</b>	<b>280.00</b>	<b>553.45</b>	<b>1546.55</b>	<b>480.00</b>
<b>Example 2</b>									
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
	<b>2100</b>	<b>1.15</b>	<b>760</b>		<b>334.35</b>	<b>280.00</b>	<b>553.45</b>	<b>1546.55</b>	<b>480.00</b>
<b>Example 3</b>									
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
	<b>2100</b>	<b>3.55</b>	<b>760</b>		<b>108.31</b>	<b>280.00</b>	<b>553.45</b>	<b>1546.55</b>	<b>480.00</b>



## NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

INCIDENT :	DATE:	IMPACTED SECURITY COORDINATOR :	ID NO:
------------	-------	---------------------------------	--------

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

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

[illegible]



## 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 PTP 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 NI transmission service and service to NL 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 NNL MW).

In summary, INTERCHANGE TRANSACTIONS would be curtailed by a total of 21.8 MW and NI transmission service and service to NL 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.

<i>Sink RA</i>	<i>Service Point</i>	<i>Scaled P Max</i>	<i>Flowgate NNL MW</i>	<i>Current NNL Relief</i>	<i>NNL Responsibility</i>		<i>NNL Responsibility Acknowledgement</i>	
					<i>Inc/Dec</i>	<i>Current Hr</i>	<i>Acknowledge Time</i>	<i>Total MW Resp.</i>
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
<b>Total</b>		<b>15291.4</b>	<b>4133.2</b>	<b>0.0</b>	<b>178.2</b>	<b>178.2</b>		<b>178.2</b>

## **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 site.

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.

### **Attachment 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 site.***

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 site and updated as necessary.
2. TLR CONSTRAINED FACILITY status and TRANSFER DISTRIBUTION FACTORS will continue to be posted to NERC TLR site.
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 site. 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 AUTHORITY will run the IDC the Reloading/Reallocation report at approximately 00:26 The IDC will prompt the RELIABILITY AUTHORITY to enter a maximum loading value. The IDC will alarm if the RELIABILITY AUTHORITY doesn’t 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 site 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 Policy 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 PSE's energy schedule as appropriate.

### ***Reallocation/Reloading Priorities***

1. INTERCHANGE TRANSACTION candidates are ranked for loading and curtailment by priority as per Appendix 9C1, Section E, "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 AUTHORITY 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 NNL responsibility<sup>3</sup> (TLR Level 5a) impacting the CONSTRAINED FACILITY,
  - SYSTEM OPERATING LIMITS or INTERCONNECTION RELIABILITY OPERATING LIMITS , known interchange impacts and BALANCING AUTHORITY NNL responsibility (TLR Level 5a) on the CONSTRAINED FACILITY the next hour, and
  - INTERCHANGE TRANSACTIONS scheduled to begin the next hour.
2. The RELIABILITY AUTHORITY will enter a maximum loading value for the CONSTRAINED FACILITY into the IDC as part of issuing the Reloading/Reallocation report.
3. The RELIABILITY AUTHORITY is allowed to call for TLR 3a or 5a when approaching a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITY must allow INTERCHANGE TRANSACTIONS to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation from (re)occurring and requiring holding or curtailments in the restricted direction.

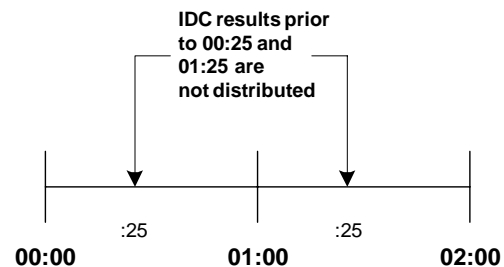
---

<sup>3</sup> Flows due to service to Network Customers and Native Load. See “**Parallel Flow Calculation Procedure Reference Document.**”

## Attachment 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 AUTHORITY to declare a TLR Level 3a or 5a any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by IDC. That is, a RELIABILITY AUTHORITY 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 AUTHORITY only for previewing purposes, and can not be distributed to the other RELIABILITY AUTHORITIES or the market. Instead, the issuing RELIABILITY AUTHORITY will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the Approved-Tag Submission Deadline for Reallocation.
3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing RELIABILITY AUTHORITY prior to 00:30 in order to provide a minimum of 30 minutes for the RELIABILITY AUTHORITIES with tags sinking in his 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 AUTHORITY 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, Page RAL-34).



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

### ***Re-Issuing of a TLR Level 2 or Higher***

Each hour, the IDC will automatically remind the issuing RELIABILITY AUTHORITY (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 AUTHORITY 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 AUTHORITY, and will take place at 00:25 so that, if the RELIABILITY AUTHORITY 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 PTP Transactions***

In order to assist a RELIABILITY AUTHORITY 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 AUTHORITY 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 AUTHORITY 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 AUTHORITY 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	$850 \text{ MW} - 800 \text{ MW} = 50 \text{ MW}$
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	$950 \text{ MW} - 50 \text{ MW} = 900 \text{ MW}$

**Example 2**

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

**Example 3**

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

For a TLR levels 3b or 5b the IDC will request the RELIABILITY AUTHORITY to provide the MW requested relief amount on the CONSTRAINED FACILITY, and will not present the current and next hour MW impact of PTP transactions. The RA-entered requested relief amount will be used by 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation on the CONSTRAINED FACILITY by the requested amount.

## ***IDC Calculations and Reporting Requirements***

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 (zero)
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 as follows:

<b><i>Priority</i></b>	<b><i>Purpose</i></b>	<b><i>Explanation and Conditions</i></b>
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.

<b>Priority</b>	<b>Purpose</b>	<b>Explanation and Conditions</b>
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 <i>after</i> 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 on page 37.

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 AUTHORITY, 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 site, 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation and all INTERCHANGE TRANSACTIONS are allowed to flow. In order to provide the RELIABILITY AUTHORITIES 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 AUTHORITIES 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 AUTHORITY with alarms, only those who issued the TLR and those whose TRANSACTIONS sink within their RELIABILITY AREA will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new TRANSACTIONS is required: TLR Level 2, 3a, 3b, 5a and 5b.

### ***Tag Adjustment***

The INTERCHANGE TRANSACTIONS with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that INTERCHANGE TRANSACTIONS were not curtailed/held and are flowing at their specified schedule amounts.

1. INTERCHANGE TRANSACTIONS marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the TRANSACTION is fully curtailed.
2. INTERCHANGE TRANSACTION marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the INTERCHANGE TRANSACTION has been previously adjusted; otherwise, if the INTERCHANGE TRANSACTION is flowing in full, the Tag Authority need not issue an adjust.
3. INTERCHANGE TRANSACTIONS marked as HOLD should be adjusted to 0 MW.

### ***Special Tag Status***

There are cases in which a tag may be marked with a composite state of ATTN\_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for reallocation. Such tags, when approved by the TAG AUTHORITY, will be marked as HOLD and must be halted.

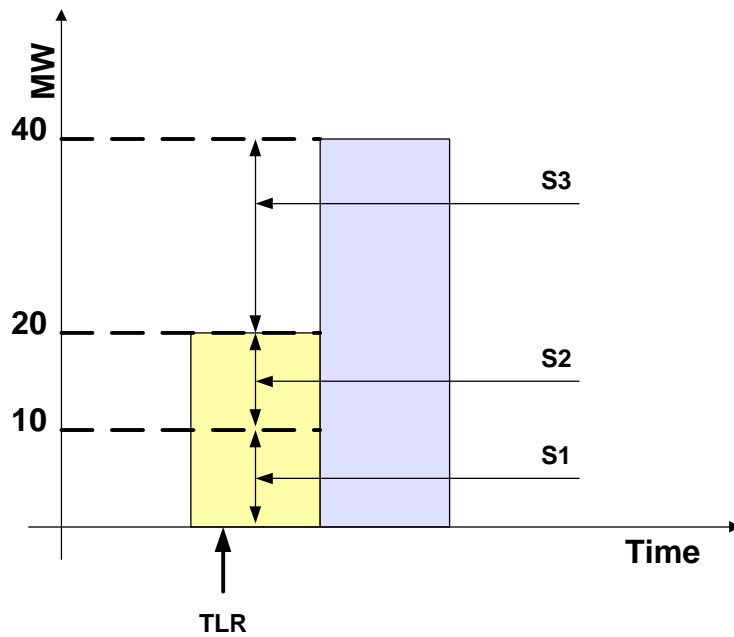
### ***Transaction Sub-Priority Examples***

The following describes examples of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service sub-priority setting for a INTERCHANGE TRANSACTION under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

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

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

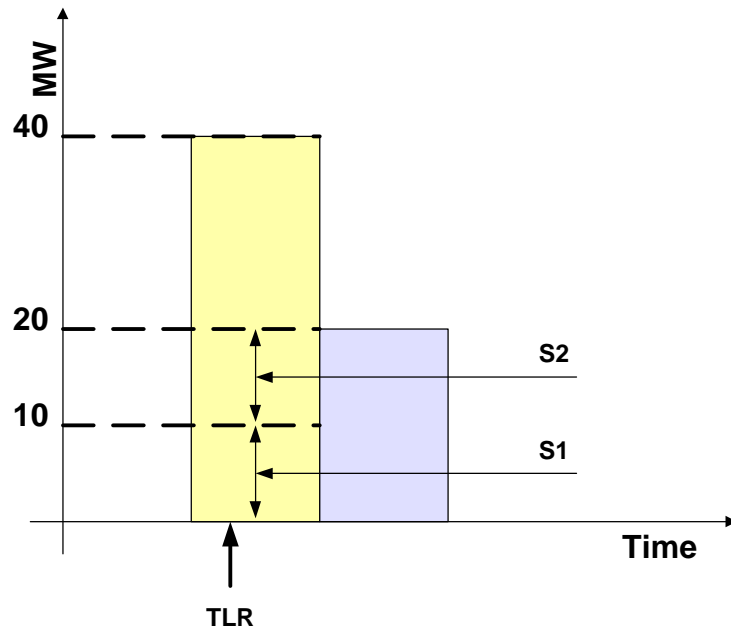
#### Sub-priorities for Transaction MW:



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

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

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

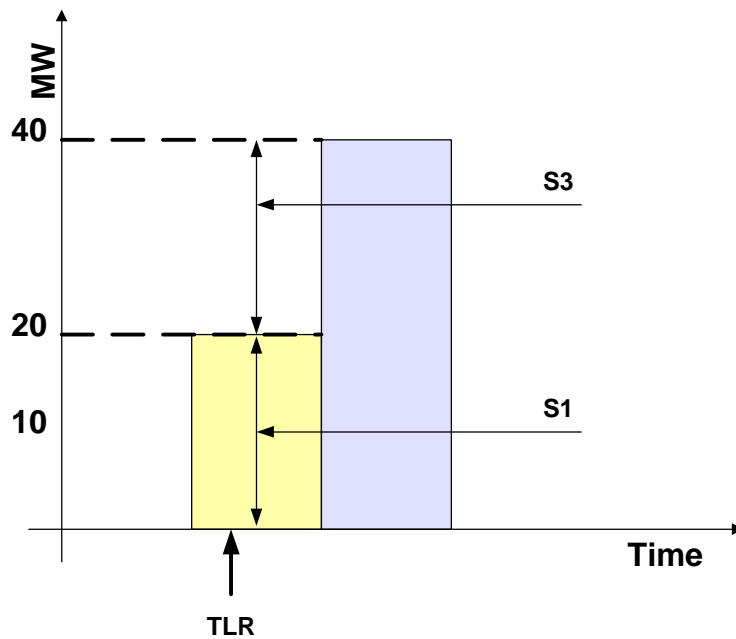


#### Sub-priorities for Transaction MW:

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

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

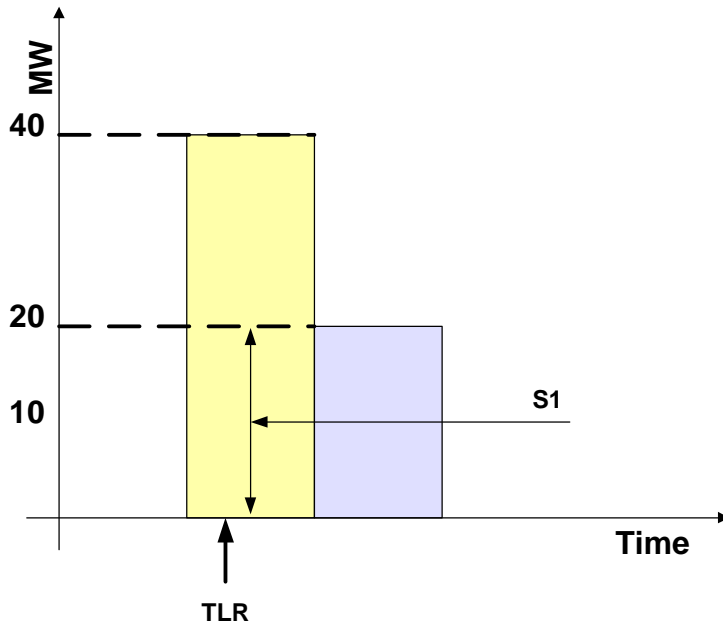
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



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

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

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

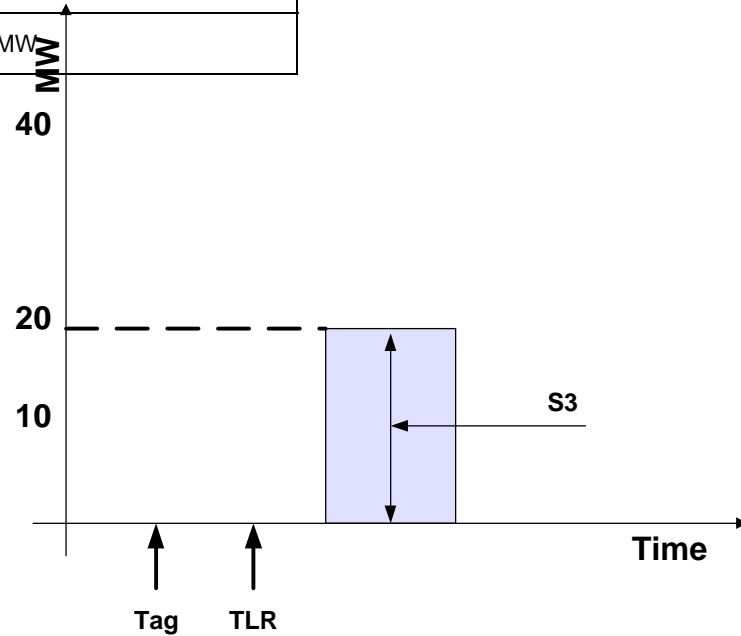


#### Sub-priorities for Transaction MW:

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

## Example 5 – TLR Issued before Transaction was scheduled to start

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

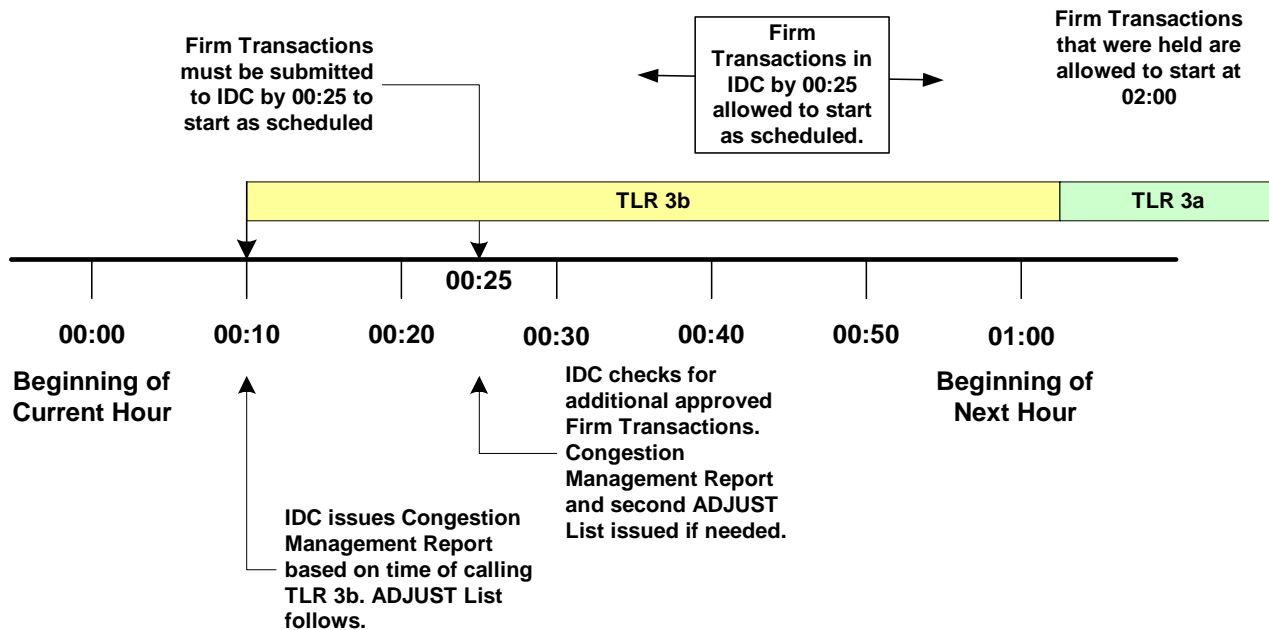


<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

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

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

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



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.

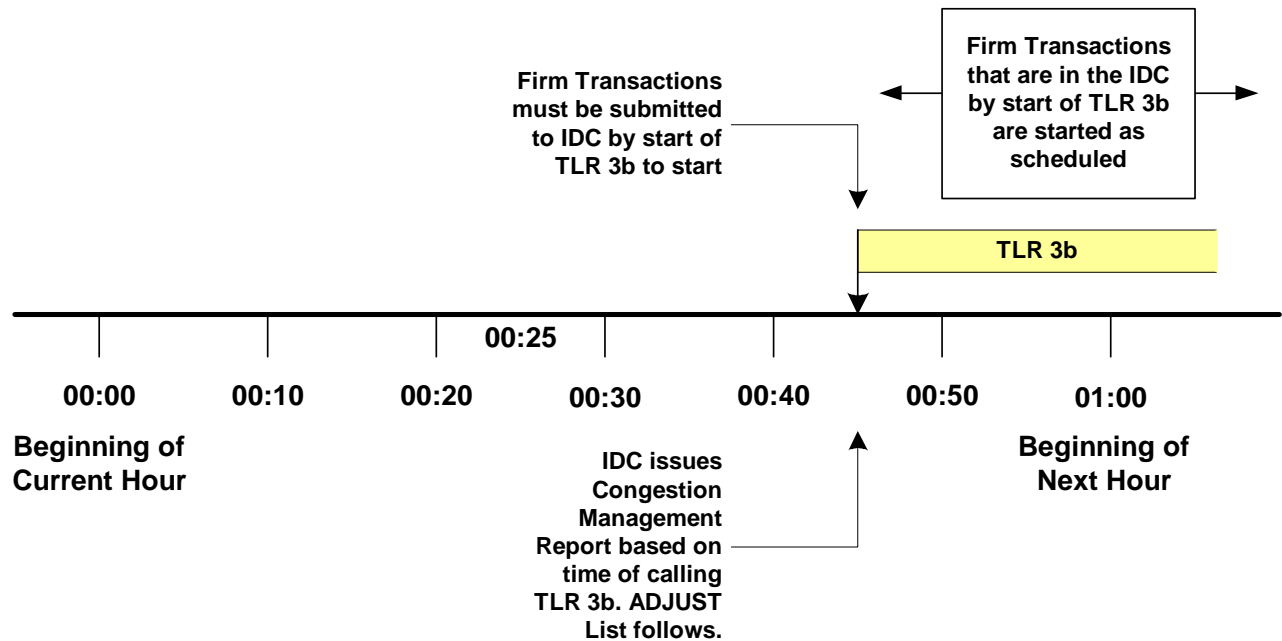
7. Once the SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation is mitigated, the RELIABILITY AUTHORITY shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:
  - a. INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were submitted to 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.



## Transmission Loading Relief Procedure

---

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.

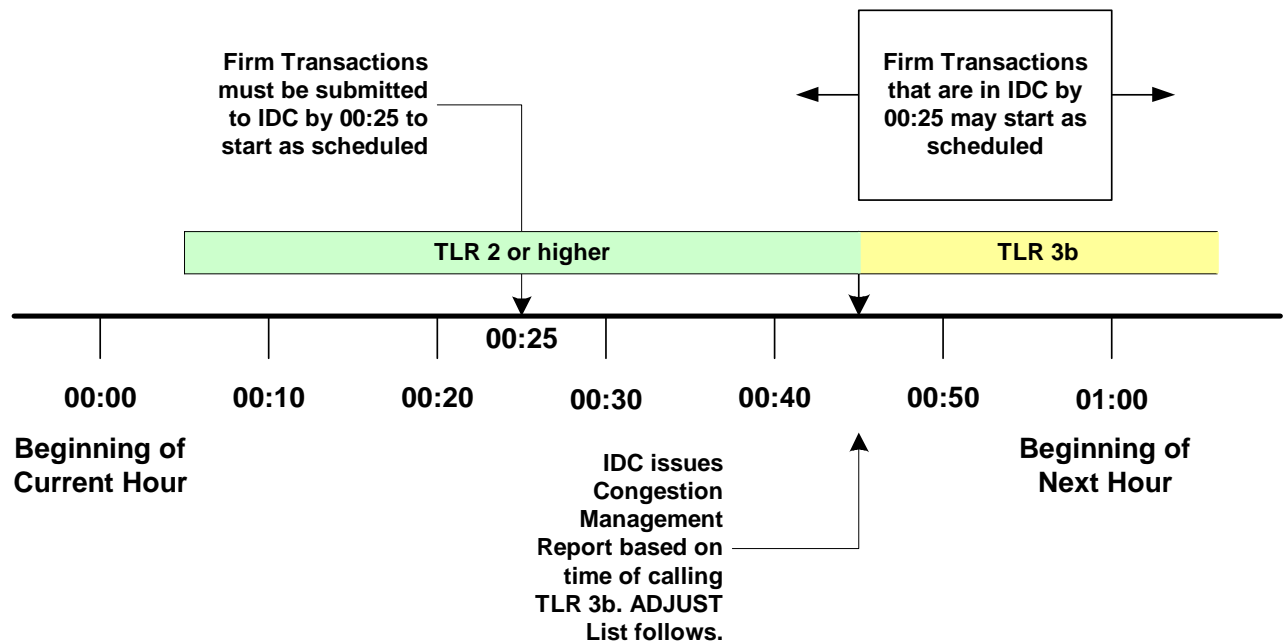


1. The IDC will examine the current hour (00) and next hour (01) for all INTERCHANGE TRANSACTIONS.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service 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.)

## Transmission Loading Relief Procedure

---

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.

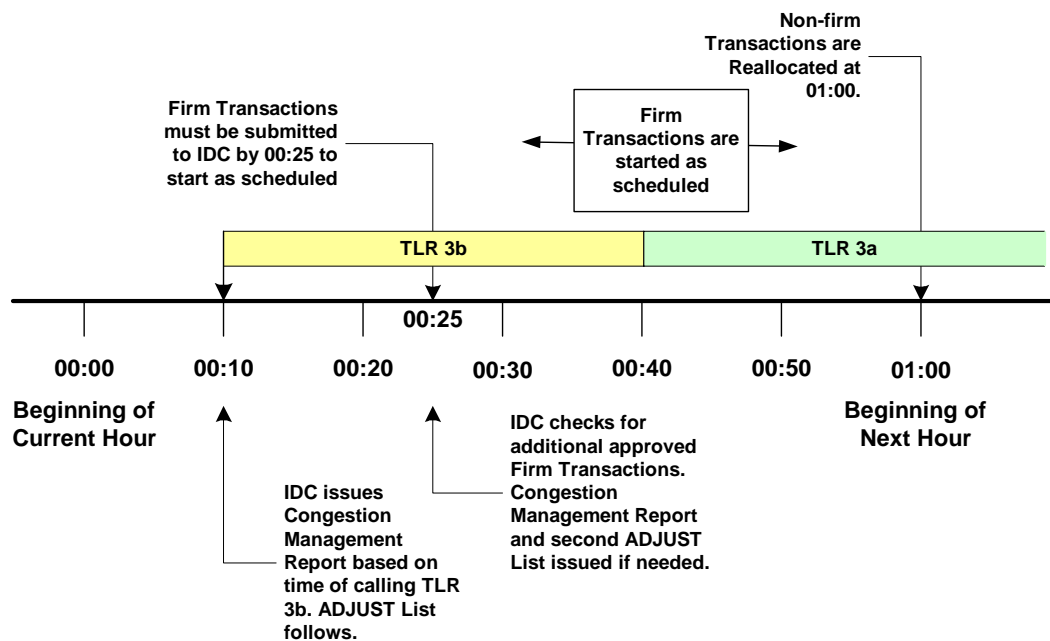


If TLR 2 or higher has been issued and 3B is subsequently issued, then only those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other INTERCHANGE TRANSACTIONS are held.

## Transmission Loading Relief Procedure

---

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.

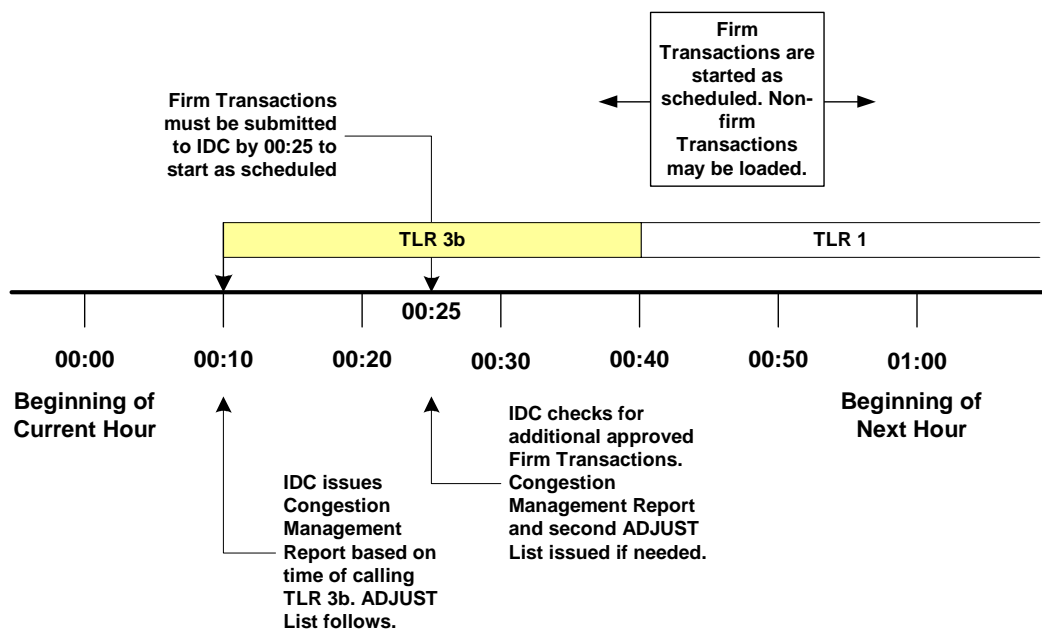


1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.
3. All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service are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

## Transmission Loading Relief Procedure

---

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.



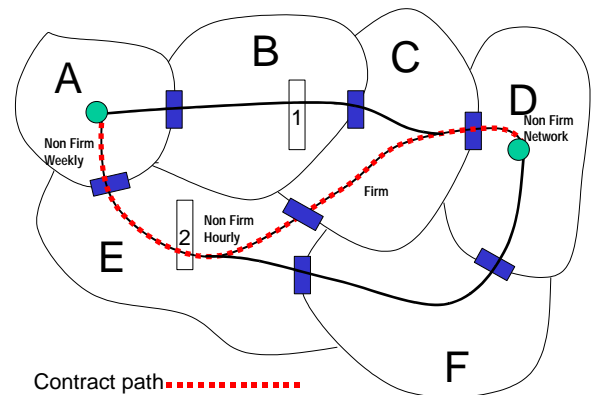
1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.
2. All INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will start as scheduled.
3. All INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service may be loaded immediately.



## Transmission Loading Relief Procedure

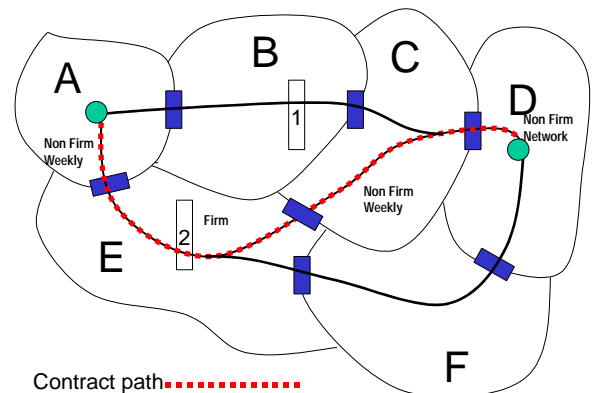
Case 3: E is a non-firm hourly path, C is firm, B has CONSTRAINT at #1.

- B may call RELIABILITY AUTHORITY for TLR Procedure 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)



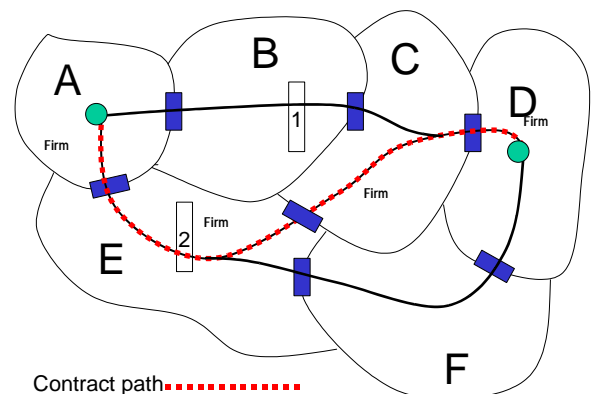
Case 4: E is a firm path; A, D, and C are Non-firm; E has CONSTRAINT at #2.

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call RELIABILITY AUTHORITY 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)



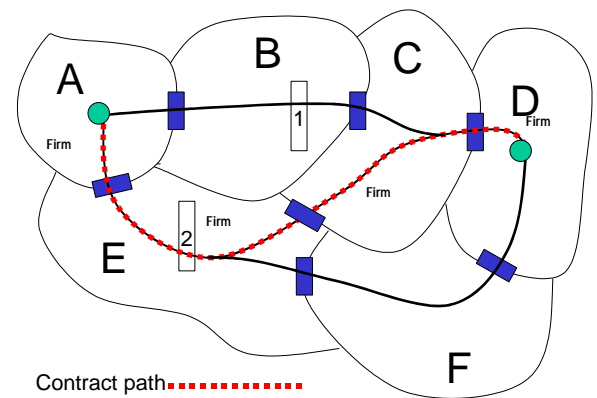
Case 5: The entire path (A-E-C-D) is firm; E has CONSTRAINT at #2.

- INTERCHANGE TRANSACTION A – D is considered Firm priority for curtailment purposes.
- E may call RELIABILITY AUTHORITY 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.

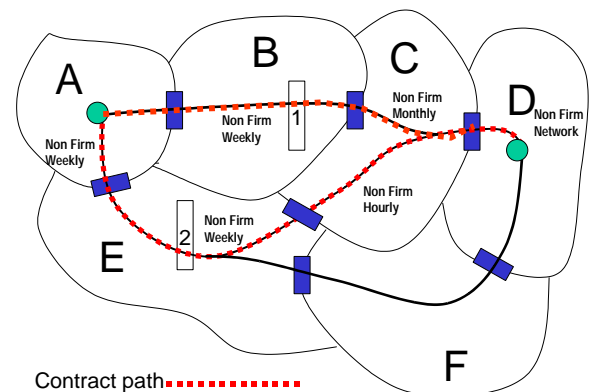
- INTERCHANGE TRANSACTION A – D is considered Firm priority for curtailment purposes.
- B may call RELIABILITY AUTHORITY for TLR Procedure for all *non-firm* INTERCHANGE TRANSACTIONS that contribute to the overload at CONSTRAINT #1.
- Following the curtailment of all non-firm INTERCHANGE TRANSACTIONS, the RELIABILITY AUTHORITY (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 for TLR Procedure to relieve overload at CONSTRAINT #1.
- If both A – D Interchange Transactions have the same TDF 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).







Supporting Documentation for NAESB TLR Standard

The NAESB TLR Standard was derived from Policy 9 Appendices 9C1, 9C1B, and 9C1C as modified by a subset of members of the NERC Version 0 drafting team (dated June 7, 2004) and presented to the drafting team on June 9-11, 2004. Sections D, G, and H of Appendix 9C1 and portions of Appendices 9C1B and 9C1C (marked in blue) were moved to an appendix because they contained no obvious requirements. Otherwise, changes are redlined as shown below.

# ~~Appendix 9C1~~ **NAESB Transmission Loading Relief Procedure—Eastern Interconnection Standard**

Version ~~2b0~~

## **A.1. General Requirements**

**1.1.1. Initiation only by RELIABILITY AUTHORITY.** ~~The NERC Transmission Loading Relief Procedure may be initiated only by a~~ RELIABILITY AUTHORITY ~~shall be the only entity authorized to initiate the NAESB Transmission Loading Relief Procedure and shall do so~~ at 1) the RELIABILITY AUTHORITY'S own request, or 2) upon the request of a TRANSMISSION OPERATOR.

**1.2. Mitigating transmission constraints.** ~~The A RELIABILITY AUTHORITY shall utilize the TLR Procedure may be used to~~ mitigate potential or actual SYSTEM OPERATING LIMIT VIOLATIONS or INTERCONNECTION RELIABILITY OPERATING LIMIT violations on any transmission facility modeled in the INTERCHANGE DISTRIBUTION CALCULATOR. ~~[See also Section 6.1, "Interchange Transactions not in the IDC.]~~

**2.1.1.2.1. Requesting relief on tie facilities.** Any TRANSMISSION OPERATOR who operates the tie facility ~~may~~ shall be allowed to request relief from its RELIABILITY AUTHORITY.

**2.1.1.2.1.1. INTERCHANGE TRANSACTION priority on tie facilities.** The priority of the INTERCHANGE TRANSACTION(S) to be curtailed ~~is~~ shall be determined by the Transmission Service reserved on the TRANSMISSION SERVICE PROVIDER'S system who requested the relief.

**3.1.3. Order of TLR Levels and taking emergency action.** The RELIABILITY AUTHORITY ~~may~~ shall not ~~necessarily be required to~~ follow the TLR Levels in their numerical order (~~See Section B Requirement 2, "TLR Levels"~~). Furthermore, if a RELIABILITY AUTHORITY deems that a transmission loading condition could jeopardize bulk system reliability, the RELIABILITY AUTHORITY ~~has~~ shall have the authority to enter TLR Level 6 directly, and immediately direct the BALANCING AUTHORITIES or TRANSMISSION OPERATORS to take such actions as re-dispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing the TLR Transaction Curtailment Procedures, or other methods, to return the system to a secure state.

## Transmission Loading Relief Procedure

**4.1.4. Notification of TLR Procedure implementation.** The RELIABILITY AUTHORITY initiating the use of the TLR Procedure ~~must~~shall notify other RELIABILITY AUTHORITIES and BALANCING AUTHORITIES and TRANSMISSION OPERATORS, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

**4.1.4.1. Notifying other RELIABILITY AUTHORITIES.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall inform all other RELIABILITY AUTHORITIES via the RELIABILITY AUTHORITY Information System (RAIS) that the TLR Procedure has been implemented.

**4.1.4.1.1. Actions expected.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall indicate the actions expected to be taken by other RELIABILITY AUTHORITIES. ~~[See also: Policy 3B and 3D for CONTROL AREA Requirements during curtailments.]~~

**4.2.1.4.2. Notifying TRANSMISSION OPERATORS and BALANCING AUTHORITIES.** RELIABILITY AUTHORITIES ~~must keep the~~shall notify TRANSMISSION OPERATORS and BALANCING AUTHORITIES in his RELIABILITY AREA ~~informed~~ when entering and leaving any TLR level.

**4.3.1.4.3. Notifying BALANCING AUTHORITIES.** The RELIABILITY AUTHORITY for the SINK BALANCING AUTHORITY ~~is~~shall be responsible for directing ~~that the~~sink BALANCING AUTHORITY to curtail the INTERCHANGE TRANSACTIONS as specified by the RELIABILITY AUTHORITY implementing the TLR Procedure. ~~[See Policy 3.D. for Control Area curtailment notification details.]~~

**4.3.1.4.3.1. 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.

**4.4.1.4.4. Updates.** At least once each hour, or when conditions change, the RELIABILITY AUTHORITY implementing the TLR Procedure shall update all other RELIABILITY AUTHORITIES (via the RAIS). TRANSMISSION OPERATORS and BALANCING AUTHORITIES who have had Interchange Transactions impacted by the TLR will be updated by their RELIABILITY AUTHORITY.

**5.1.5. Obligations.** All RELIABILITY AUTHORITIES shall comply with the request of the RELIABILITY AUTHORITY who initiated the TLR Procedure, unless the initiating RELIABILITY AUTHORITY agrees otherwise.

**5.1.5.1. Use of TLR Procedure with “local” procedures.** A RELIABILITY AUTHORITY ~~may~~shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, ~~he is~~the RELIABILITY AUTHORITY shall be obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY AUTHORITY desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, he may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.<sup>1</sup>

---

<sup>1</sup> Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local re-dispatch procedure.

## Transmission Loading Relief Procedure

**6.1.6. Consideration of Interchange Transactions.** The administration of the TLR Procedure ~~is~~ shall be guided by information obtained from the Interchange Distribution Calculator (IDC).

**6.1.1.6.1. Interchange Transactions not in the IDC.** RELIABILITY AUTHORITIES shall also treat known INTERCHANGE TRANSACTIONS that may not appear in the IDC in accordance with the procedures in this document.

**6.2.1.6.2. Transmission elements not in IDC.** When a RELIABILITY AUTHORITY is faced with an overload on a transmission element that is not modeled in the IDC, the RELIABILITY AUTHORITY shall use the best information available to curtail INTERCHANGE TRANSACTIONS in order to operate the system in a reliable manner. The RELIABILITY AUTHORITY shall use his 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 AUTHORITY (or TRANSMISSION OPERATOR through his RELIABILITY AUTHORITY) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use his best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating RELIABILITY AUTHORITY. 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 AUTHORITIES are involved in the TLR event, all impacted RELIABILITY AUTHORITIES shall be in agreement ~~must be reached with the initiating RELIABILITY AUTHORITIES on~~ before any adjustments to the curtailment list ~~are made~~.

**6.4.1.6.4. Curtailment that would cause a constraint elsewhere.** ~~If the~~ The RELIABILITY AUTHORITY ~~is aware that~~ shall be allowed to exempt an INTERCHANGE TRANSACTION from curtailment if the RELIABILITY AUTHORITY is aware that the INTERCHANGE TRANSACTION curtailment directed by the IDC would cause a constraint to occur elsewhere, ~~after consulting if the RELIABILITY AUTHORITY has consulted~~ with those RELIABILITY AUTHORITIES who initiated the curtailment, ~~he may exempt that INTERCHANGE TRANSACTION from curtailment.~~

**6.5.1.6.5. Re-dispatch options.** The RELIABILITY AUTHORITY shall ensure that INTERCHANGE TRANSACTIONS that are linked to re-dispatch options are protected from curtailment in accordance with the re-dispatch provisions. ~~{See also: Policy 9C. Req. 3.2.1.1 on use of local procedures.}~~

**6.6.1.6.6. Reallocation.** During a TLR Level 3A, TRANSACTIONS The RELIABILITY AUTHORITY shall consider for Reallocation any TRANSACTIONS of

## Transmission Loading Relief Procedure

higher priority that meet the Approved-tag Submission Deadline ~~for Reallocation will be considered for REALLOCATION~~ during a TLR Level 3A. ~~(see Appendix 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a.”)~~ During a TLR Level 5A, TRANSACTIONS using Firm Transmission Service will be considered for REALLOCATION ~~if they have met the same tag submission deadlines.~~ The RELIABILITY AUTHORITY shall consider for Reallocation any TRANSACTION using Firm Transmission Service that has met the Approved-tag Submission Deadline during a TLR Level 5A.

**7.1.9. IDC updates.** Any INTERCHANGE TRANSACTION adjustments or curtailments that result from using this Procedure must be entered into the IDC ~~as explained in Policy 9.C.~~ Requirement 1.1.

**8.1.10. Logging.** The RELIABILITY AUTHORITY shall complete the NERC Transmission Loading Relief Procedure Log ~~(Section I)~~ whenever he invokes TLR Level 2 or above, and send a copy of the log via e-mail to the NERC staff within two business days of the TLR event. The staff ~~will~~ shall post these logs on the NERC web site upon receipt.

**9.1.11. TLR Event Review.** The RELIABILITY AUTHORITY 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.

**9.1.1.9.1. Providing information.** TRANSMISSION OPERATORS and BALANCING AUTHORITIES within the RELIABILITY AUTHORITY’S RELIABILITY AREA, and all other RELIABILITY AUTHORITIES, including TRANSMISSION OPERATORS and BALANCING AUTHORITIES within their respective RELIABILITY AREAS, shall provide information, as requested by the initiating RELIABILITY AUTHORITY, in accordance with TLR review processes established by NERC.

**9.2.1.9.2. 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.

**9.3.1.9.3. Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for “lessons learned”

## **B.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 AUTHORITY 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. ~~(Section E., “Principles for Mitigating Constraints On and Off the Contract Path”)~~ It is important to note, ~~as explained in the Introduction,~~ 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.

### **TLR Levels**

#### **1.2.1. TLR Level 1 – Notify RELIABILITY AUTHORITIES of potential SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violations.**

##### **Circumstances:**

##### **1.1.2.1.1. The RELIABILITY AUTHORITY shall use following circumstances to establish the need for TLR Level 1:**

- The transmission system is secure.
- The RELIABILITY AUTHORITY foresees a transmission or generation contingency or other operating problem within his RELIABILITY AREA that could cause one or more transmission facilities to approach or exceed their **SYSTEM OPERATING LIMIT** or **INTERCONNECTION RELIABILITY OPERATING LIMIT**.

##### **1.2.2.1.2. Notification procedures.** The RELIABILITY AUTHORITY shall notify all RELIABILITY AUTHORITIES via the Reliability Authority Information System as soon as the condition is foreseen. All affected RELIABILITY AUTHORITIES shall check to ensure that INTERCHANGE TRANSACTIONS are posted in the INTERCHANGE DISTRIBUTION CALCULATOR.

#### **2.2.2. TLR Level 2 – Hold transfers at present level to prevent SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violations**

##### **2.1.2.2.1. Circumstances** The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering ~~this level~~ **TLR Level 2:**

- The transmission system is secure,

- One or more transmission facilities are expected to approach, or are approaching, or are at their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.

**2.2.2.2.2.** **Holding procedures.** The RELIABILITY AUTHORITY ~~may~~shall ~~be allowed to~~ hold the implementation of any additional INTERCHANGE TRANSACTIONS that are at or above the CURTAILMENT THRESHOLD. However, the RELIABILITY AUTHORITY 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 ~~will~~shall be allowed to start.

**2.2.1.2.2.3.** 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 AUTHORITY ~~must~~shall document this action on the TLR Log.

**3.2.3.** **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.**

**3.1.2.3.1.** **~~Circumstances~~** ~~The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering this level~~ The RELIABILITY AUTHORITY shall use 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT
- 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. ~~(See Section 3.2 below)~~

**3.2.2.3.2.** **Reallocation procedures to allow INTERCHANGE TRANSACTIONS using higher priority Point-to-Point Transmission Service to start.** The RELIABILITY AUTHORITY 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 C~~ Requirement 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 Requirement 6. ~~The specifications for performing this Reallocation, as well as the Tagging requirements, are found in Appendix 9C1B,~~ **“Interchange Transaction Reallocation During TLR Level 3a and 5a.”**

**3.2.1.2.3.2.1.** ~~INTERCHANGE TRANSACTIONS using higher priority Non-firm or Firm Transmission Service will~~ The RELIABILITY AUTHORITY shall displace INTERCHANGE TRANSACTIONS with lower priority Transmission Service using INTERCHANGE TRANSACTIONS having higher priority Non-firm or Firm Transmission Service.

**3.2.2.2.3.2.2.** ~~The RELIABILITY AUTHORITY shall not curtail~~ INTERCHANGE TRANSACTIONS using Non-firm Transmission Service ~~will not be curtailed~~ to allow the start or increase of another INTERCHANGE TRANSACTION having the same priority Non-firm Transmission Service.

**3.2.3.2.3.2.3.** ~~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 AUTHORITY will~~ shall proceed to TLR Level 5a. ~~(See Section 6, “TLR Level 5a,” and Appendix 9C1B “Interchange Transaction Curtailments During TLR Levels 3a and 5a,” for Reallocation of Interchange Transactions using Firm Point-to-Point Transmission Service)~~

**3.2.4.2.3.2.4.** ~~Reloading of~~ The RELIABILITY AUTHORITY shall reload curtailed INTERCHANGE TRANSACTIONS ~~will precede starting prior to allowing the start~~ of new or increased INTERCHANGE TRANSACTIONS.

**3.2.4.1.2.3.2.4.1.** ~~Interchange Transactions whose tags were submitted to the Tag Authority 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.~~

**3.2.5.2.3.2.5.** ~~Transmission capability available for reloading or starting~~ will ~~shall~~ be filled by eligible TRANSACTIONS on a pro-rata basis.

**3.2.6.2.3.2.6.** ~~Transactions~~ The RELIABILITY AUTHORITY shall consider transactions whose tags meet the Approved-tag Submission Deadline for ~~Reallocation~~ reallocation ~~(see~~



~~Appendix 9C1B, “Interchange Transaction Reallocation During TLR Level 3a and 5a,” Section B)~~ will be considered ~~for reallocation~~ for the upcoming hour. Tags submitted after this deadline ~~will~~shall be considered for reallocation the following hour.

#### **4.2.4. TLR Level 3b – Curtail INTERCHANGE TRANSACTIONS using Non-Firm Transmission Service Arrangements to mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation**

##### **4.1.2.4.1. ~~Circumstances~~The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering ~~this level~~TLR Level 3b:**

- One or more transmission facilities are operating above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken, or
- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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.

##### **4.2.2.4.2. Holding new INTERCHANGE TRANSACTIONS.** The RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation. The RELIABILITY AUTHORITY shall allow INTERCHANGE 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 9C1C, Requirement 7.~~ **“Interchange Transaction Curtailments During TLR Level 3b.”**

##### **4.3.2.4.3. Curtailment procedures to mitigate an SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.** The RELIABILITY AUTHORITY shall curtail INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD as specified in ~~Section C~~Requirement 3. **“Interchange Transaction Curtailment Order.”**



### **5.2.5. TLR Level 4 – Reconfigure Transmission**

**5.1.2.5.1.** ~~Circumstances~~ The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering ~~this level~~ TLR Level 4:

- One or more Transmission Facilities are above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken

**5.2.2.5.2.** **Holding new INTERCHANGE TRANSACTIONS.** The RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation. The RELIABILITY AUTHORITY shall allow INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service ~~will be allowed~~ to start if they are submitted to the IDC by 00:25 or the time at which the TLR Level 4 is called, whichever is later.

**5.3.2.5.3.** **Reconfiguration procedures.** Following the curtailment of all INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD in Level 3b that impact the CONSTRAINED FACILITIES, if a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation is imminent or occurring, the RELIABILITY ~~AUTHORITY~~ AUTHORITY (IES) 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 E~~ Requirement 4., “Principles for Mitigating Constraints On and Off the Contract Path”

**6.2.6. 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.**

#### **Circumstances:**

**6.1.2.6.1.** The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure
- One or more transmission facilities are at their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT
- 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation.
- No further transmission reconfiguration is possible or effective.

**6.2.2.6.2.** **Reallocation procedures to allow new INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to start.** ~~Reallocation~~ The RELIABILITY AUTHORITY shall use the following three-step process for reallocation of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service ~~is a three-step process as follows:~~

**6.2.1.2.6.2.1.** **Step 1 – Identify available re-dispatch options.** The RELIABILITY AUTHORITY shall assist the TRANSMISSION OPERATOR(s) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY AUTHORITY shall proceed to implement these options while proceeding to Steps 2 and 3 below.

**6.2.2.2.6.2.2.** **Step 2 –** The RELIABILITY AUTHORITY 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 F~~ **Requirement 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service."**

**6.2.3.2.6.2.3.** **Step 3 – Curtail Interchange Transactions using Firm Transmission Service.** The RELIABILITY AUTHORITY 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 2.7.2.2** over the CONSTRAINED FACILITIES. (See also ~~Appendix 9C1B~~ **Requirement 6, "Interchange Transaction Reallocation During TLR 3a and 5a."** The RELIABILITY AUTHORITY 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 re-dispatch options will continue to be implemented.

**7.2.7. TLR Level 5b – Curtail INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service to mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation.**

**Circumstances:**

**7.1.2.7.1. The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering TLR Level 5b:**

- One or more Transmission Facilities are operating above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT, or
- Such operation is imminent, or
- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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.

**7.2.2.7.2. ~~Curtailment~~The RELIABILITY AUTHORITY shall use the following three-step process for curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service ~~is a three-step process as follows:~~**

**7.2.1.2.7.2.1. Step 1 – Identify available re-dispatch options.** The RELIABILITY AUTHORITY shall assist the TRANSMISSION OPERATORS(S) in identifying those known re-dispatch options that are available to the Transmission Customer that will mitigate the loading on the CONSTRAINED FACILITIES. If such re-dispatch options are deemed insufficient to mitigate loading on the CONSTRAINED FACILITIES, the RELIABILITY AUTHORITY shall proceed to implement these options while proceeding to Steps 2 and 3 below.

**7.2.2.2.7.2.2. Step 2 –** The RELIABILITY AUTHORITY 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 F Requirement 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.”**

**7.2.3.2.7.2.3. Step 3 – Curtailment of Interchange Transactions using Firm Transmission Service.** At this point, the

RELIABILITY AUTHORITY 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation has been mitigated. The RELIABILITY AUTHORITY 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 re-dispatch options will continue to be implemented.

### **8.2.8. TLR Level 6 – Emergency Procedures**

#### **Circumstances:**

#### **8.1.2.8.1. The RELIABILITY AUTHORITY shall use following circumstances to establish the need for entering TLR Level 6:**

- One or more Transmission Facilities are above their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT.
- One or more Transmission Facilities *will* exceed their SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT upon the removal from service of a generating unit or another transmission facility.

#### **8.2.2.8.2. Implementing emergency procedures.** If the RELIABILITY AUTHORITY deems that SOL or IROL violations are imminent, the RELIABILITY AUTHORITY shall immediately direct the BALANCING AUTHORITIES and TRANSMISSION OPERATORS in his RELIABILITY AREA to re-dispatch 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 AUTHORITY.

### **2.9. TLR Level 0 – TLR concluded**

#### **9.TLR Level 0—TLR concluded**

#### **9.1.4.1.1. Interchange TRANSACTION restoration and notification procedures.** The RELIABILITY AUTHORITY initiating the TLR Procedure shall notify all RELIABILITY AUTHORITIES within the INTERCONNECTION via the RAIS when the SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violations are mitigated and the system is in a “normal” state, allowing INTERCHANGE TRANSACTIONS to be reestablished at his discretion. Those with the highest transmission priorities shall be reestablished first if possible.



### **C.3. Interchange Transaction Curtailment Order**

#### **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. Hourly Service – NH**

**Priority 3. Daily Service – ND**

**Priority 4. Weekly Service – NW**

**Priority 5. 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 AUTHORITY ~~will~~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:

**2.1.13.2.1.1.** **TLR Level 3a.** Enable INTERCHANGE TRANSACTIONS using a higher Transmission reservation priority to be implemented, or

**2.1.23.2.1.2.** **TLR Level 3b.** Mitigate an SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation.

~~The INTERCHANGE TRANSACTION curtailment priority is determined by its TRANSMISSION SERVICE reservation over the constrained facility(ies) as shown in the box on the right.~~

~~The curtailment priority for INTERCHANGE TRANSACTIONS that do not have a Transmission Service reservation over the constrained facility(ies) is the lowest priority of the individual reserved transmission segments.~~

##### **Transmission Service Priorities**

**Priority 0. Next-hour Market Service – NX\***

**Priority 1. Service over secondary receipt and delivery points – NS**

**Priority 2. Hourly Service – NH**

**Priority 3. Daily Service – ND**

**Priority 4. Weekly Service – NW**

**Priority 5. 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**

**~~C. Interchange Transaction Curtailment Order~~**

**3.3. Curtailment of Interchange Transactions Using Firm Transmission Service**

**3.3.1.** The RELIABILITY AUTHORITY ~~will~~shall direct the curtailment of INTERCHANGE TRANSACTIONS using Firm TRANSMISSION SERVICE that are at or above the CURTAILMENT THRESHOLD for the following TLR Levels:

**3.1.13.3.1.1.** **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

**3.1.23.3.1.2.** **TLR Level 5b.** Mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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.

## **SECTION D MOVED TO APPENDIX**

---



## **E.4. Principles for Mitigating Constraints On and Off the Contract Path**

---

### **1.1 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 RELIABILITY AUTHORITIES must agree on how the NERC Transmission Loading Relief Procedure will handle these INTERCHANGE TRANSACTIONS to, first, ensure the operational security of the INTERCONNECTION and, second, respect the obligations of the TRANSMISSION PROVIDERS’ tariffs.

The curtailment priority of an INTERCHANGE TRANSACTION depends on whether the CONSTRAINED FACILITY is on or off the contract path, and, if on the contract path, the Transmission Service of the link with the CONSTRAINED FACILITY.

The RELIABILITY AUTHORITY must also consider 1) the tariff obligations of the Transmission Provider with the CONSTRAINED FACILITY, 2) the Transmission Customer’s re-dispatch or other congestion management arrangements, and 3) arrangements among the TRANSMISSION PROVIDERS for handling certain CONSTRAINTS. ~~Refer to examples beginning on page A9C1-2.~~

### **4.1. Principles for Constraints ON the Contract Path**

**4.1.1.** ~~The RELIABILITY AUTHORITY initiating TLR shall consider the entire INTERCHANGE TRANSACTION non-firm. If if~~ the transmission link ~~with-on~~ the CONSTRAINED FACILITY is Non-firm Point-to-Point Transmission Service, ~~the entire INTERCHANGE TRANSACTION is considered non-firm,~~ 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.

#### **4.1.1.1.**

**Discussion.** The TRANSMISSION OPERATOR simply has to call its RELIABILITY AUTHORITY, 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 ~~Principle #2~~Requirement 4.1.2 below.)

**E. Principles for Mitigating Constraints On and Off the Contract Path**

**4.1.2.** The RELIABILITY AUTHORITY initiating TLR shall consider the entire INTERCHANGE TRANSACTION firm ~~If~~ if the transmission link ~~with on~~ the CONSTRAINED FACILITY is Firm Point-to-Point Transmission Service, ~~the entire INTERCHANGE TRANSACTION is considered firm,~~ even if other links in the contract path are non-firm.

**4.1.2.1.1. 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. ~~For~~ Constraints OFF the Contract Path**

**4.2.1.** The RELIABILITY AUTHORITY initiating TLR shall consider the entire INTERCHANGE TRANSACTION non-firm if non of the transmission links on the contract path are on the CONSTRAINED FACILITY and ~~If~~ if any of the transmission links on the contract path are Non-firm Point-to-Point Transmission Service, ~~the INTERCHANGE TRANSACTION is~~ shall considered non-firm by the system with the CONSTRAINED FACILITY that is not on the contract path, and takes on the lowest transmission service priority of all TRANSMISSION SERVICE links along the contract path.

**4.2.1.1. 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.** 4The RELIABILITY AUTHORITY initiating TLR shall consider the entire INTERCHANGE TRANSACTION firm if ~~If~~ all of the transmission links on

**E. Principles for Mitigating Constraints On and Off the Contract Path**

the contract path ~~with the CONSTRAINED FACILITY~~ are Firm Point-to-Point Transmission Service, even if non of the transmission links are on the CONSTRAINED FACILITY then the INTERCHANGE TRANSACTION is considered firm and ~~will~~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.

**4.2.2.1.**

**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 AUTHORITY 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.

Sections in Blue were moved to the appendices

## 1.2 Examples

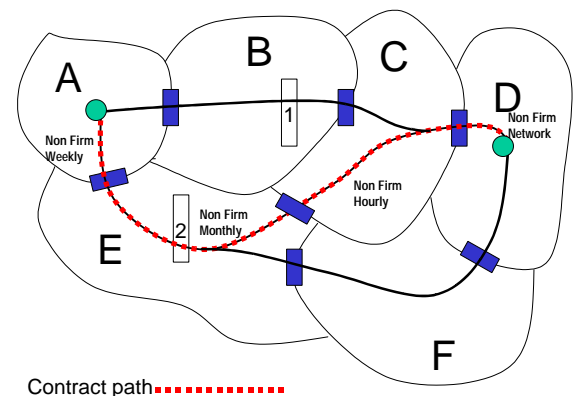
This section explains, by example, the obligations of the TRANSMISSION SERVICE PROVIDERS on and off the contract path when calling for Transmission Loading Relief. (References to Principles refer to [Section E Requirement 4](#), “Principles for Mitigating Constraints On and Off the Contract Path,” on 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 [Section F Requirement 5](#), “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service”.

### 1.2.1 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

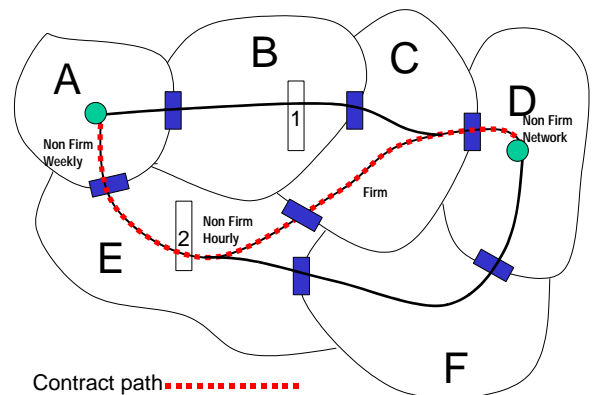
### 1.2.2 Case 1: E is a non-firm Monthly path, C is non-firm Hourly; E has CONSTRAINT at #2.

- E may call RELIABILITY AUTHORITY for TLR Procedure 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)



### 1.2.3 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 RELIABILITY AUTHORITY for TLR Procedure 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

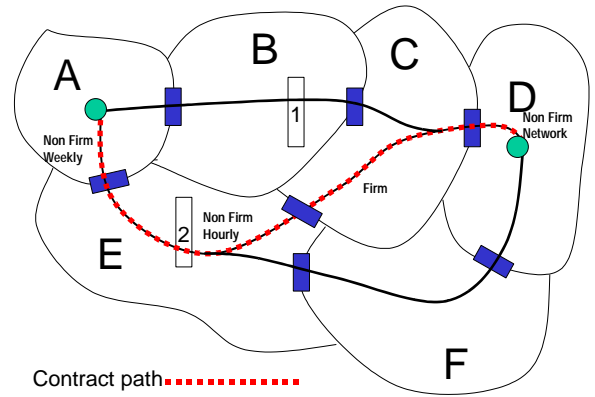


**E. Principles for Mitigating Constraints On and Off the Contract Path**

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)

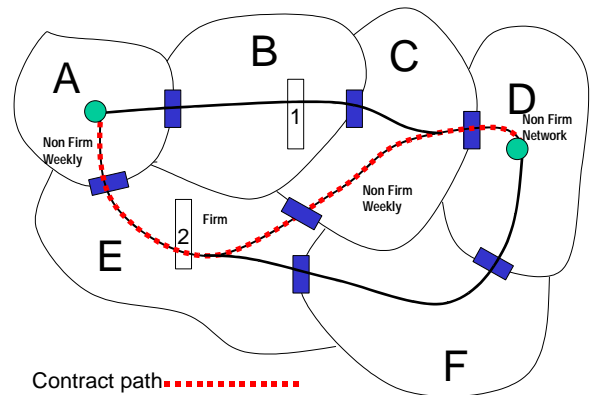
**1.2.4 Case 3: E is a non-firm hourly path, C is firm, B has CONSTRAINT at #1.**

- B may call RELIABILITY AUTHORITY for TLR Procedure 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)



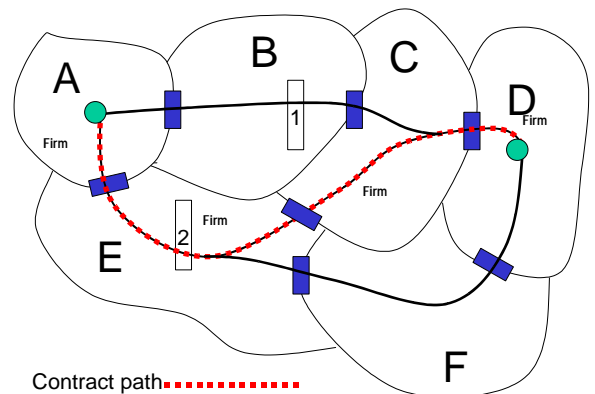
**1.2.5 Case 4: E is a firm path; A, D, and C are Non-firm; E has CONSTRAINT at #2.**

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call RELIABILITY AUTHORITY 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)



**1.2.6 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 RELIABILITY AUTHORITY 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)



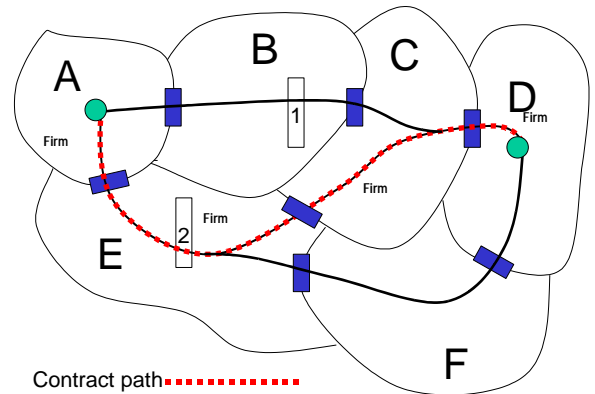
## Appendix 9C1—Transmission Loading Relief Procedure

### E. Principles for Mitigating Constraints On and Off the Contract Path

- 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)

#### 1.2.7 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 RELIABILITY AUTHORITY for TLR Procedure 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 AUTHORITY (ies) will determine which TRANSMISSION OPERATOR(S) will reconfigure their transmission, if possible, to mitigate constraint #1. (Principle 4)

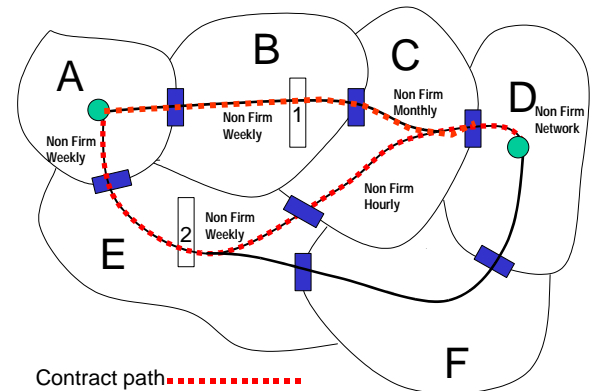


- A-D transaction may be curtailed as a result. However, the A-D transaction is treated as a firm INTERCHANGE TRANSACTION and will be curtailed only after non-firm INTERCHANGE TRANSACTIONS. (Note: This means that the firm contract path is respected by all parties, including those not on the contract path.) (Principle 4)

#### 1.2.8 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 for TLR Procedure to relieve overload at CONSTRAINT #1.

If both A – D Interchange Transactions have the same TDF 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).





## **F.5. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service**

[See also “Parallel Flow Calculation Procedure Reference Document”]

### **1.3 Introduction**

The provision of Point-to-Point (PTP) transmission service, Network Integration (NI) transmission service and service to Native Load (NL) results in parallel flows on the transmission network of other TRANSMISSION OPERATORS. When a transmission facility becomes constrained, ~~NERC Policy 9C, Appendix 9C1, calls for~~ 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 Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using Non-firm PTP 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 PTP transmission service, NI transmission service and service to NL (TLR Level 5a and 5b). ~~The NERC TLR Procedure requires that the e~~Curtailment of Firm PTP transmission service ~~shall~~ be accompanied by the comparable curtailment of NI transmission service and service to NL to the degree that these three transmission services contribute to the CONSTRAINT.

#### **5.1. Basic PrinciplesGeneral Requirements**

A methodology, called the Per Generator Method Without Counter Flow, or simply the Per Generator Method, has been programmed into the INTERCHANGE DISTRIBUTION CALCULATOR (IDC) to calculate the portion of parallel flows on any CONSTRAINED FACILITY due to service to NL of each BALANCING AUTHORITY (BA). The ~~basic principles following general requirements are necessary followed~~ to assure comparable REALLOCATION or CURTAILMENT of firm transmission services ~~s are~~:

**1.5.1.1.** The RELIABILITY AUTHORITY initiating a curtailment shall identify for curtailment ~~All~~ all firm transmission services (i.e. PTP, NI and service to NL) that contribute to the flow on any CONSTRAINED FACILITY by an amount greater than or equal to the CURTAILMENT THRESHOLD ~~must be curtailed~~ on a pro rata basis.

**2.5.1.2.** For Firm PTP transmission services, the TRANSFER DISTRIBUTION FACTORS (TDFs) must be greater than or equal to the CURTAILMENT THRESHOLD.

**3.5.1.3.** For NI transmission service and service to NL, the generator-to-load distribution factors (GLDFs) must be greater than or equal to the CURTAILMENT THRESHOLD. The GLDF on a specific CONSTRAINED FACILITY for a given generator within a BALANCING AUTHORITY is defined as the generator's contribution to the flow on that flowgate when supplying the load of that BALANCING AUTHORITY.

**4.5.1.4.** The Per Generator Method ~~assigns~~ shall assign the amount of CONSTRAINED FACILITY relief that must be achieved by each



## **Appendix 9C1—Transmission Loading Relief Procedure**

### **F. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service**

BALANCING AUTHORITY'S NI transmission service or service to NL. It ~~does~~shall not specify how the reduction will be achieved.

**5.5.1.5.** ~~The Per Generator Method places an obligation on all~~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.

**6.5.1.6.** The implementation of the Per Generator Method ~~must~~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 NI transmission service or service to NL ~~is~~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 ~~are~~shall be calculated from a single bus location in the IDC model. The LSFs ~~are~~shall be defined as a general scaling of the native load within each BALANCING AUTHORITY. The Generator to Load Distribution Factor (GLDF) ~~is~~shall be calculated as the GSF minus the LSF. The ~~IDC~~ all generators assigned to native load for which the GLDF is greater than or equal to the CURTAILMENT THRESHOLD.

SECTIONS IN BLUE WERE MOVED TO AN APPENDIX

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

#### **1.4 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 PTP 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 NI transmission service and service to NL 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>NNL MW).

In summary, INTERCHANGE TRANSACTIONS would be curtailed by a total of 21.8 MW and NI transmission service and service to NL 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.

**Appendix 9C1—Transmission Loading Relief Procedure**

**F. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service**

Sink RA	Service Point	Scaled P Max	Flowgate NNL MW	Current NNL Relief	NNL Responsibility		NNL 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		15291.4	4133.2	0.0	178.2	178.2		178.2

**1.4.1**

**~~Appendix 9C1~~—Transmission Loading Relief Procedure**

---

**~~F. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service~~**

SECTIONS G AND H MOVED TO AN APPENDIX

# ~~Appendix 9C1B—Interchange Transaction Reallocation During TLR Levels 3a and 5a~~

~~Version 1a~~

## ~~Appendix Subsections~~

---

~~A. Basic Principles~~

~~B. Communication and Timing Requirements~~

~~C. How the IDC Handles Reallocation~~

~~Attachment A—Summary of IDC Features that Support Transaction Reloading/Reallocation~~

~~Attachment B—Timing Requirements~~

---

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

### Introduction

This ~~Appendix standard~~ 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 ~~Appendix 9C1, “TLR Procedure—Eastern Interconnection,” Section B Requirement 2.3, “TLR Level 3a.”~~) When a ~~NERC~~ TLR Level 3a is in effect, RELIABILITY AUTHORITIES 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 ~~Appendix 9C1, “TLR Procedure—Easton Interconnection,” Section B Requirement 2.6, “TLR Level 5a.”~~)

#### A.6.1. Basic General Principles Requirements

---

The basic ~~principles requirements~~ for TRANSACTION REALLOCATION are built upon the premises of FERC Order 888, NERC Operating Policies and current business practices. Specifically, the key ~~principles requirements~~ are:

1.6.1.1. When identifying Transaction transactions for REALLOCATION will the RELIABILITY AUTHORITY 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.

2.6.1.2. When identifying transactions for REALLOCATION, the RELIABILITY AUTHORITY shall ~~Only only consider~~ those INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD for which a TLR 2 or higher is called, ~~are affected by the Reallocation procedure.~~

3.6.1.3. When identifying transactions for REALLOCATION, the RELIABILITY AUTHORITY shall ~~displace INTERCHANGE TRANSACTIONS utilizing lower priority transmission service with~~ INTERCHANGE TRANSACTIONS ~~with utilizing~~ higher transmission service priority, ~~will displace~~ INTERCHANGE TRANSACTIONS using lower priority transmission service.

4.6.1.4. When identifying transactions for REALLOCATION, the RELIABILITY AUTHORITY shall ~~not curtail~~ INTERCHANGE TRANSACTIONS using Non-firm Transmission Service ~~will not be curtailed~~ to allow the start or increase of another transaction having the same Non-Firm Transmission Service priority (marginal “bucket”).

5.6.1.5. When identifying transactions for REALLOCATION, the RELIABILITY AUTHORITY shall ~~reload~~ ~~Reloading of~~ curtailed INTERCHANGE TRANSACTIONS ~~will prior to precede~~ starting ~~of~~ new or ~~increased~~ ~~increasing existing~~ INTERCHANGE TRANSACTIONS.

6.6.1.6. INTERCHANGE TRANSACTIONS whose tags were submitted to the Tag Authority 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 C~~ **Requirement 6.2, “Communications and Timing Requirements”**), ~~would~~ ~~shall~~ be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed INTERCHANGE TRANSACTION.

7.6.1.7. The RELIABILITY AUTHORITY shall reload or start all ~~e~~Eligible TRANSACTIONS ~~will be reloaded or started~~ on a pro-rata basis.

8.6.1.8. INTERCHANGE TRANSACTIONS whose tags meet the Approved-Tag Submission Deadline for Reallocation (see ~~Section C~~ **Requirement 6.2, “Communications and Timing Requirements”**) ~~will~~ ~~shall~~ be considered for reallocation for the upcoming hour. (However, INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service ~~will~~ ~~shall~~ be allowed to start as scheduled.) INTERCHANGE TRANSACTIONS whose tags are submitted to the Interchange Distribution Calculator after the Approved-Tag Submission Deadline for Reallocation will be considered for Reallocation the following hour. This applies to INTERCHANGE TRANSACTIONS using either Non-firm Point-to-Point Transmission Service ~~and 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 ~~will~~shall be held and then allowed to start in the upcoming hour.

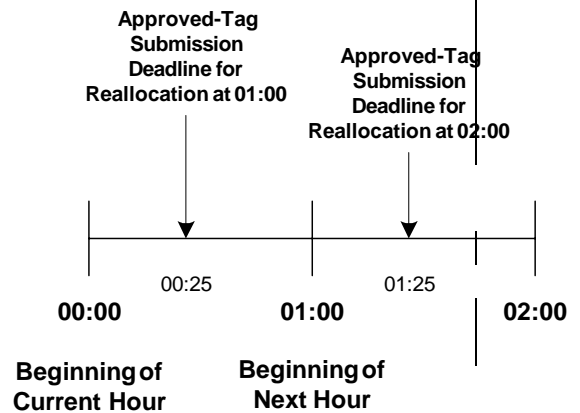
It should be noted that calling a TLR 3a does not necessarily mean that INTERCHANGE TRANSACTIONS using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the Approved-Tag Submission Deadline for Reallocation requirements and allow for a coordinated assessment of all INTERCHANGE TRANSACTIONS tagged to start the upcoming hour.

## **B.6.2. Communication and Timing requirements**

~~When in a TLR 3a or 5a, the~~ The following timeline ~~is shall be utilized to required 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 ~~is~~ shall be referenced as 00:00. The beginning of the next hour ~~is~~ shall be referenced as 01:00. ~~The end of the next hour shall be referenced as 02:00~~ (see Figure 1 at right).

**6.2.2. Approved-Tag Submission Deadline for Reallocation.** Reliability Authorities shall consider all Approved-approved Tags for INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD ~~must be that have been~~ submitted to the Interchange Distribution Calculator by 00:25 ~~to be considered~~ for Reallocation at 01:00. (See Figure 1 at the right). (However, INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.)



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

**6.2.2.1. Reliability Authorities shall consider all approved Tags-tags** submitted to the Interchange Distribution Calculator beyond these deadlines (for both Firm and Non-firm Point-to-Point Transmission Service) which will not be allowed to start or increase at 01:00 but will be considered ~~for~~ REALLOCATION at 02:00.

**6.2.2.2. As soon as the TLR level is reduced to 1 or 0, the** Approved-Tag Submission Deadline for Reallocation ~~is shall no longer 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 ~~will 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-tags submitted for reallocation and shall will be evaluated by the appropriate BALANCING AUTHORITIES and TRANSMISSION PROVIDERS. ~~The BALANCING AUTHORITY and~~

~~TRANSMISSION PROVIDER~~ are expected to communicate approval or rejection (via the Tag Approval) by 00:25.

**6.2.5. Collective Scheduling Assessment Period.** ~~At 00:25, t~~<sup>4</sup>The initiating RELIABILITY AUTHORITY (the one who called and still has a TLR 3a or 5a in effect) shall ~~at this time (00:25)~~ run the IDC to obtain a three-part list of INTERCHANGE TRANSACTIONS including their transaction status:

**1.6.2.5.1.** INTERCHANGE TRANSACTIONS that may start, increase, or reload ~~will~~ shall have a status of PROCEED,

**2.6.2.5.2.** 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 ~~will~~ shall have a status of CURTAILED, and

**3.6.2.5.3.** INTERCHANGE TRANSACTIONS that are entered into the IDC after 00:25 ~~will~~ shall have a status of HOLD<sup>2</sup> and be considered for REALLOCATION at 02:00. Also, INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service submitted to the Tag Authority after TLR 2 or higher was declared (“post-tagged”) but have not been allowed to start ~~will~~ 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).

---

<sup>2</sup> The use of PROCEED, CURTAILED, and HOLD refer to an Interchange Transaction status in the IDC, not the E-tag status.



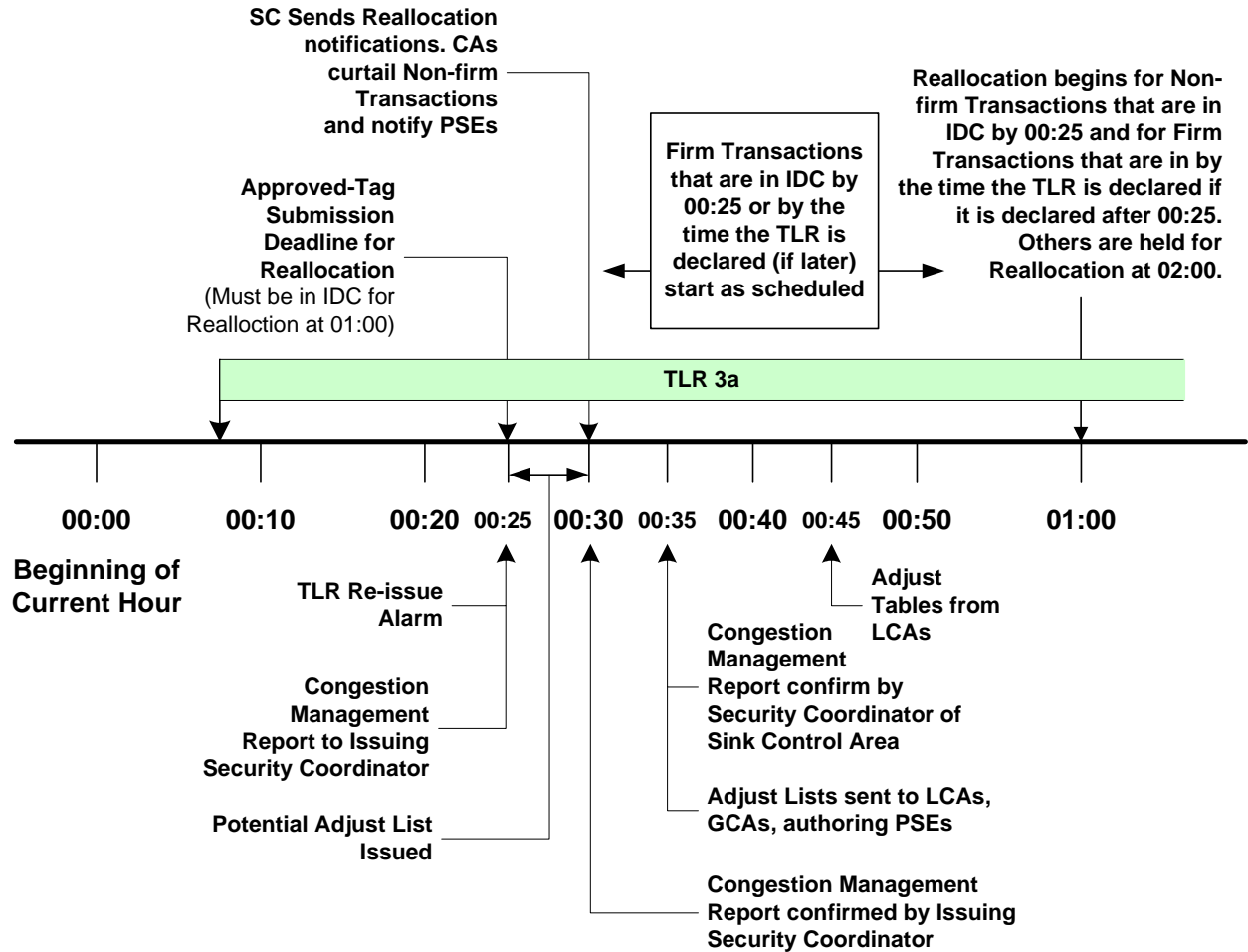
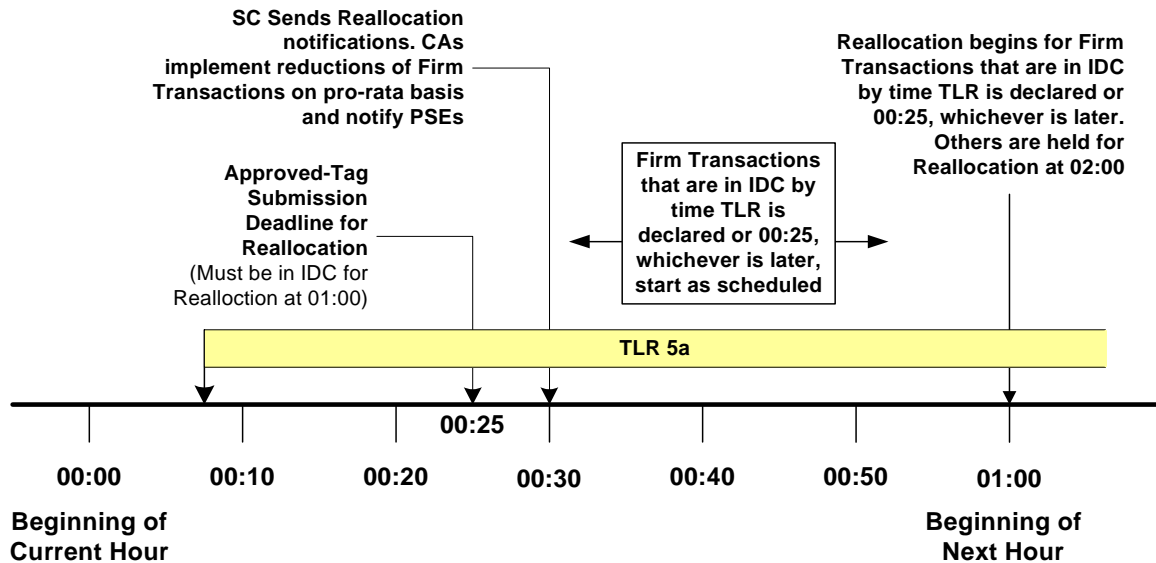


Figure 2 - Reallocation timing for TLR 3a called at 00:08.



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

6.2.5.4 The initiating RELIABILITY ~~RELIABILITY AUTHORITY~~ shall communicate the list to the appropriate sink RELIABILITY AUTHORITIES 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 AUTHORITY 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 ~~will~~ shall allow the RELIABILITY AUTHORITIES 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 ~~will~~ shall not be permitted to start or increase the next hour.**

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 AUTHORITY ~~will~~ shall have an option to specify the maximum loading of the CONSTRAINED FACILITY by all INTERCHANGE TRANSACTIONS using Point-to-Point Transmission Service. This allows the RELIABILITY AUTHORITY to take into consideration SYSTEM OPERATING LIMITS or INTERCONNECTION RELIABILITY OPERATING LIMITS and changes in TRANSACTIONS using other than point-to-point service taken under the OATT. 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY

OPERATING LIMIT violation and hence triggering the declaration of a TLR 3b or 5b.

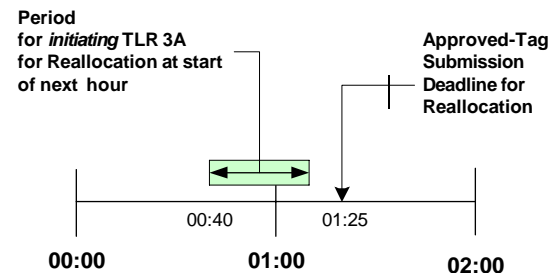
6.2.5.7. Notification of INTERCHANGE TRANSACTION status ~~will shall be provided go~~ from the IDC to the RELIABILITY AUTHORITIES via an IDC Report. ~~The RELIABILITY AUTHORITIES shall communicate this information will be communicated from the RELIABILITY AUTHORITIES to the BALANCING AUTHORITIES and TRANSMISSION OPERATORS by present methods.~~ ~~Coordination of INTERCHANGE TRANSACTION changes including new INTERCHANGE TRANSACTIONS will be implemented according to existing practices depicted in Policy 3.~~

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

6.2.6. **Customer Preferences on Timing to Call TLR 3a or 5a.** ~~A RELIABILITY AUTHORITY will call a TLR 2 or 3a whenever he deems necessary to indicate that a transmission facility is approaching its SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT. 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.~~ RELIABILITY AUTHORITIES 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 for REALLOCATION, from a Transmission Customer perspective, it is preferable that the RELIABILITY AUTHORITY call a TLR 3a within a certain time period to allow for tag preparation and submission. See Figure 4.

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 Interchange Distribution Calculator 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-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 AUTHORITY 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 AUTHORITY'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.**

SECTIONS IN BLUE WERE MOVED TO AN APPENDIX

## **C.2. How the IDC Handles Reallocation**

The Interchange Distribution Calculator 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 site.

A summary of IDC features that support the reallocation process is provided in Attachment A. Details on the interface and display features are provided in Attachment B.

## **Attachment A – 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:

### **1.5 Information posted from IDC to NERC TLR site.**

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 site and updated as necessary.
2. TLR CONSTRAINED FACILITY status and TRANSFER DISTRIBUTION FACTORS will continue to be posted to NERC TLR site.
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 site. This will provide an indication to the market of priority of INTERCHANGE TRANSACTIONS that may be Reloaded/Reallocated the following hours.

### **1.6 IDC Logic, IDC Report, and Timing**

1. The RELIABILITY AUTHORITY will run the IDC the Reloading/Reallocation report at approximately 00:26 The IDC will prompt the RELIABILITY AUTHORITY to enter a maximum loading value. The IDC will alarm if the RELIABILITY AUTHORITY doesn’t 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 Interchange Distribution Calculator 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 Interchange Distribution Calculator 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.

### **1.7 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 site 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 Policy 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 PSE's energy schedule as appropriate.

### **1.8 Reallocation/Reloading Priorities**

1. INTERCHANGE TRANSACTION candidates are ranked for loading and curtailment by priority as per Appendix 9C1, Section E, "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 Interchange Distribution Calculator 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 Interchange Distribution Calculator 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 Interchange Distribution Calculator by the time the TLR is declared.

### **1.9 Total Flow Value on a Constrained Facility for Next Hour**

1. The RELIABILITY AUTHORITY 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 NNL responsibility<sup>3</sup> (TLR Level 5a) impacting the CONSTRAINED FACILITY,
  - SYSTEM OPERATING LIMITS or INTERCONNECTION RELIABILITY OPERATING LIMITS, known interchange impacts and BALANCING AUTHORITY NNL responsibility (TLR Level 5a) on the CONSTRAINED FACILITY the next hour, and
  - INTERCHANGE TRANSACTIONS scheduled to begin the next hour.
2. The RELIABILITY AUTHORITY will enter a maximum loading value for the CONSTRAINED FACILITY into the IDC as part of issuing the Reloading/Reallocation report.
3. The RELIABILITY AUTHORITY is allowed to call for TLR 3a or 5a when approaching a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT 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 AUTHORITY must allow INTERCHANGE TRANSACTIONS to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation from (re)occurring and requiring holding or curtailments in the restricted direction.

---

<sup>3</sup> Flows due to service to Network Customers and Native Load. See “Parallel Flow Calculation Procedure Reference Document.”

## Attachment B – Timing Requirements

### 1.10 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 AUTHORITY to declare a TLR Level 3a or 5a any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by IDC. That is, a RELIABILITY AUTHORITY 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 AUTHORITY only for previewing purposes, and can not be distributed to the other RELIABILITY AUTHORITIES or the market. Instead, the issuing RELIABILITY AUTHORITY will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the Approved-Tag Submission Deadline for Reallocation.
3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing RELIABILITY AUTHORITY prior to 00:30 in order to provide a minimum of 30 minutes for the RELIABILITY AUTHORITIES with tags sinking in his 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 AUTHORITY 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, Page RAL-~~4213~~).

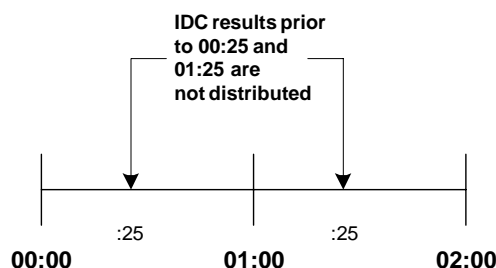


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

### 1.11 Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing RELIABILITY AUTHORITY (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 AUTHORITY 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 AUTHORITY, and will take place at 00:25 so that, if the RELIABILITY AUTHORITY 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.

### 1.12 IDC Assistance with Next Hour PTP Transactions

In order to assist a RELIABILITY AUTHORITY 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 AUTHORITY 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 AUTHORITY 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 AUTHORITY 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”:

### 1.12.1 Example 1

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

### 1.12.2 Example 2

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

### 1.12.3 Example 3

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

For a TLR levels 3b or 5b the IDC will request the RELIABILITY AUTHORITY to provide the MW requested relief amount on the CONSTRAINED FACILITY, and will not present the current and next hour MW impact of PTP transactions. The RA-entered requested relief amount will be used by 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation on the CONSTRAINED FACILITY by the requested amount.

### 1.13 IDC Calculations and Reporting Requirements

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 (zero)
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 as follows:

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 on page ~~45~~~~46~~.

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 Interchange Distribution Calculator 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 AUTHORITY, 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 site, and it is NERC's responsibility to format and publish the report.

#### 1.14 Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the CONSTRAINED FACILITY is no longer under SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation and all INTERCHANGE TRANSACTIONS are allowed to flow. In order to provide the RELIABILITY AUTHORITIES 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.

### 1.15 *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 AUTHORITIES 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 AUTHORITY 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.

### 1.16 *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.

### 1.17 *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.

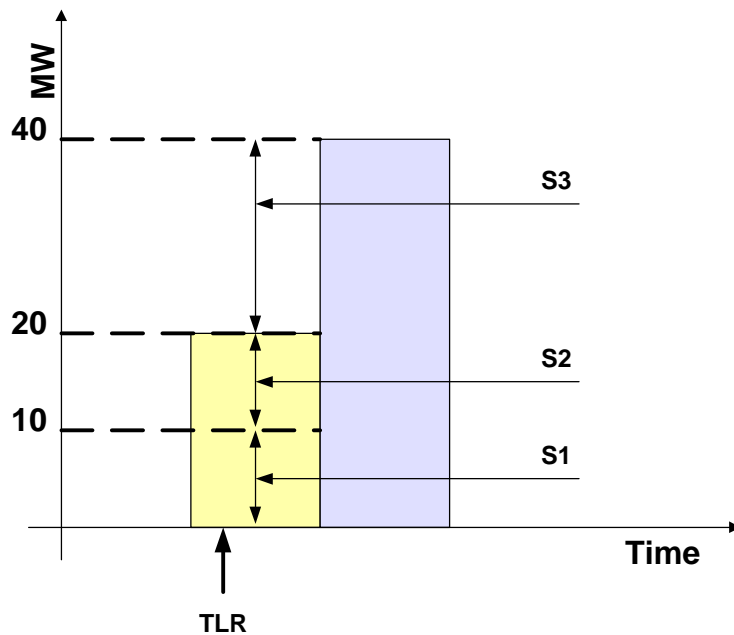
### 1.18 *Transaction Sub-Priority Examples*

The following describes examples of INTERCHANGE TRANSACTIONS using Non-firm Transmission Service sub-priority setting for a INTERCHANGE TRANSACTION under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

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

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

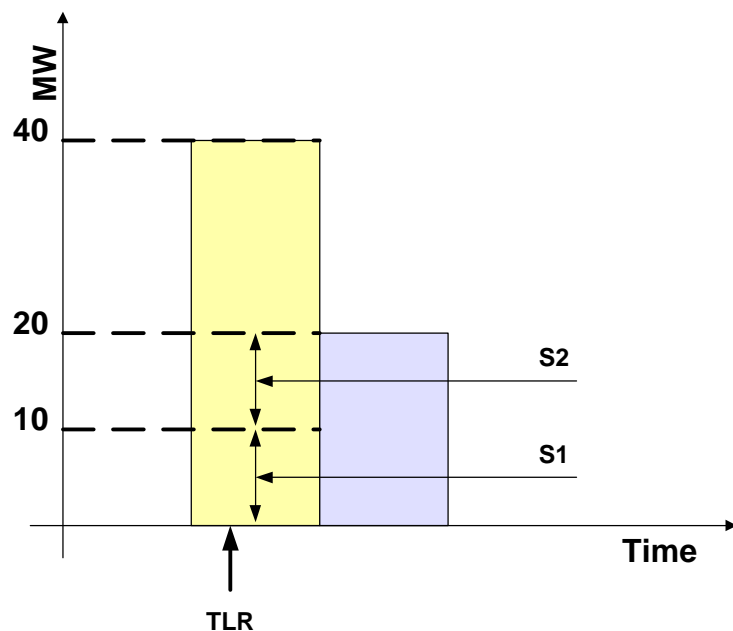
#### 1.18.1.1 Sub-priorities for Transaction MW:



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		

### 1.18.2 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



### 1.18.3

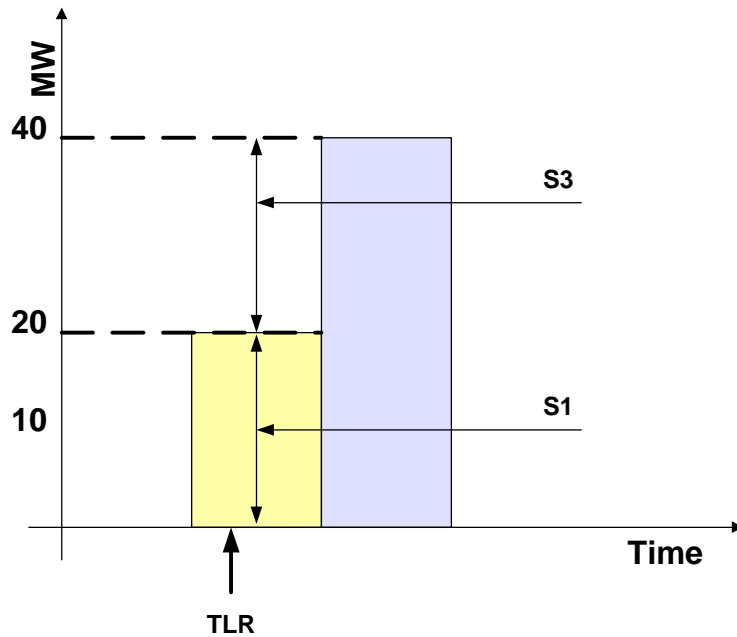
#### 1.18.3.1 Sub-priorities for Transaction MW:

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		

#### 1.18.4 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

1.18.5

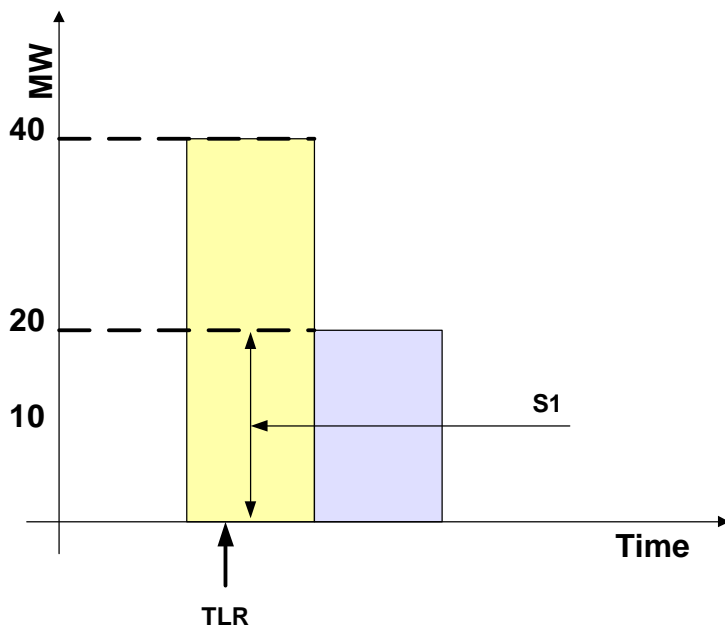


Sub-Priority	MW Value	Explanation
S1	20 MW	Maintain current flow (not curtailed)
S2	+0 MW	Reload to lesser of current and next-hour Energy Profile
S3	+20 MW	Next-hour Energy Profile is 40MW
S4		

### 1.18.6 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

### 1.18.7



#### 1.18.7.1 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		



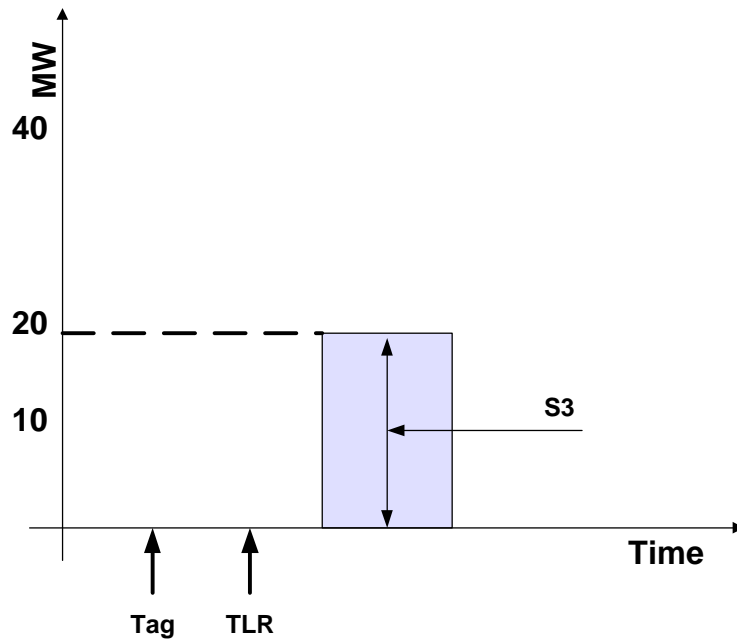
### 1.18.8 Example 5 – TLR Issued before Transaction was scheduled to start

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

1.18.9

1.18.10

1.18.10.1



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 9C1C – Interchange Transaction Curtailments During TLR Level 3b~~

~~Version 4~~

## ~~Appendix Subsections~~

~~A. Basic Principles~~

~~B. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service~~

## 7. Interchange Transaction Curtailments During TLR Level 3b

### Introduction

This ~~Appendix standard~~ provides the details for implementing TLR Level 3b, which curtails INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to assist the RELIABILITY AUTHORITY to recover from SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violations.

TLR Level 3b curtails INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are at or above the CURTAILMENT THRESHOLD. (See ~~Appendix 9C1, “TLR Procedure—Eastern Interconnection,” Section B 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 Section C, “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.

### A. Basic Principles Requirements

~~1.7.1.~~ The RELIABILITY AUTHORITY shall be allowed to call a TLR 3b ~~may be called~~ at any time to help ~~the RELIABILITY AUTHORITY~~ mitigate a SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT violation.

~~2.7.2.~~ The RELIABILITY AUTHORITY shall ~~only consider~~ only those INTERCHANGE TRANSACTIONS at or above the CURTAILMENT THRESHOLD ~~will be considered~~ for curtailment, holding, or halting.

~~3.7.3.~~ The RELIABILITY AUTHORITY shall curtail ~~Existing-existing~~ INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service ~~will be curtailed~~ as necessary to provide the required relief on the CONSTRAINED FACILITY.

~~4.7.4.~~ The RELIABILITY AUTHORITY shall curtail additional INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service to provide ~~room~~ transmission capacity for INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission

~~Service if those~~ If INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service are scheduled to start during the current hour or the following hour, ~~additional INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service will be curtailed to provide room for those INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service.~~

~~5.7.5.~~ The RELIABILITY AUTHORITY shall not allow ~~Existing-existing~~ INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are not curtailed ~~will not be allowed~~ to increase (they may flow at the same or reduced level).

~~6.7.6.~~ The RELIABILITY AUTHORITY shall not ~~Rreallocate There is no Reallocation of~~ INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service during a TLR 3b.

~~7.7.7.~~ The RELIABILITY AUTHORITY shall allow INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service ~~will be allowed~~ to start as explained in ~~Section C~~ Appendix F, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”

~~8.7.8.~~ The RELIABILITY AUTHORITY shall progress to TLR Level 5b as necessary ~~If, there is still insufficient room 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, ~~and there is insufficient room for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled, the RELIABILITY AUTHORITY will progress to TLR Level 5b as necessary.~~

~~9.7.9.~~ The ~~common interconnect model utilized by the RELIABILITY AUTHORITIES (i.e. the IDC)~~ will issue ADJUST Lists to the Generation and Load Control Areas and the PURCHASING-SELLING ENTITY who submitted the tag. The ADJUST List will include:

~~a.7.9.1.~~ INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are to be curtailed, halted, or held during ~~Current-current~~ and ~~Next~~ next hours.

~~b.7.9.2.~~ INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in ~~Section C~~ below Appendix F).

~~10.7.10.~~ The LOAD BALANCING AUTHORITY ~~must shall~~ send the ADJUST ~~Tables-Lists~~ back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

~~11.7.11.~~ The RELIABILITY AUTHORITY ~~may shall be allowed to~~ call a TLR Level 3a as soon as the SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT -Violation has been mitigated.

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

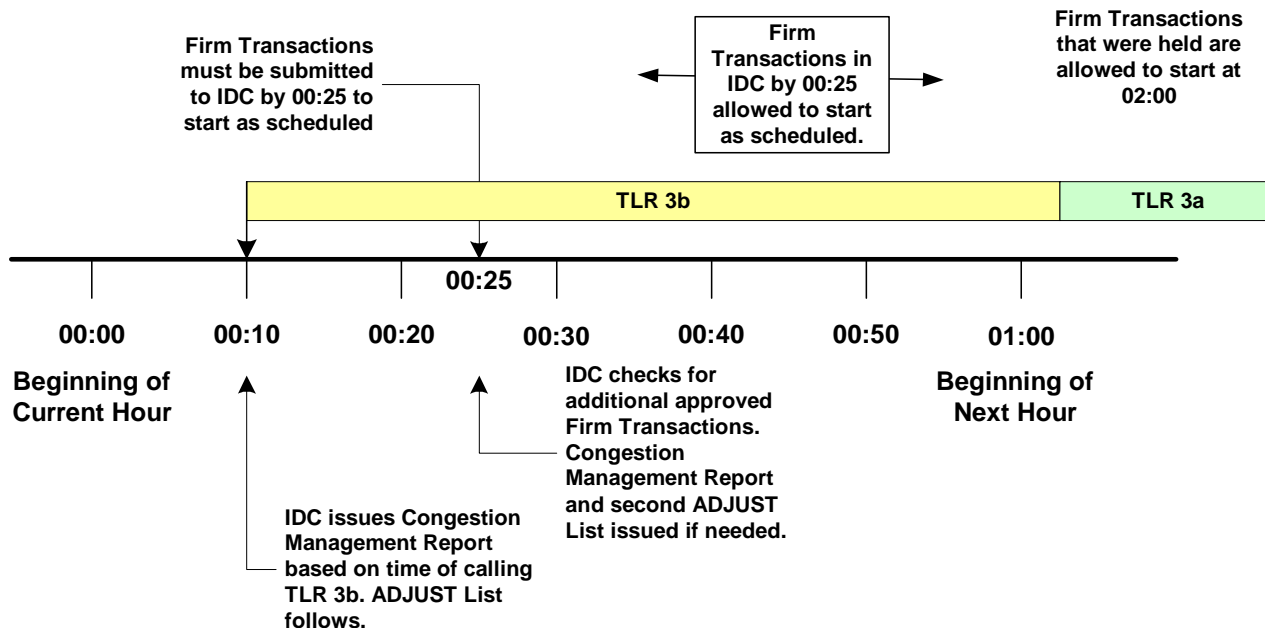
~~b.7.11.2.~~ Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see ~~Appendix 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a,” Section B Requirement 6.2).~~

SECTIONS IN BLUE MOVED TO AN APPENDIX

## **B. 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:

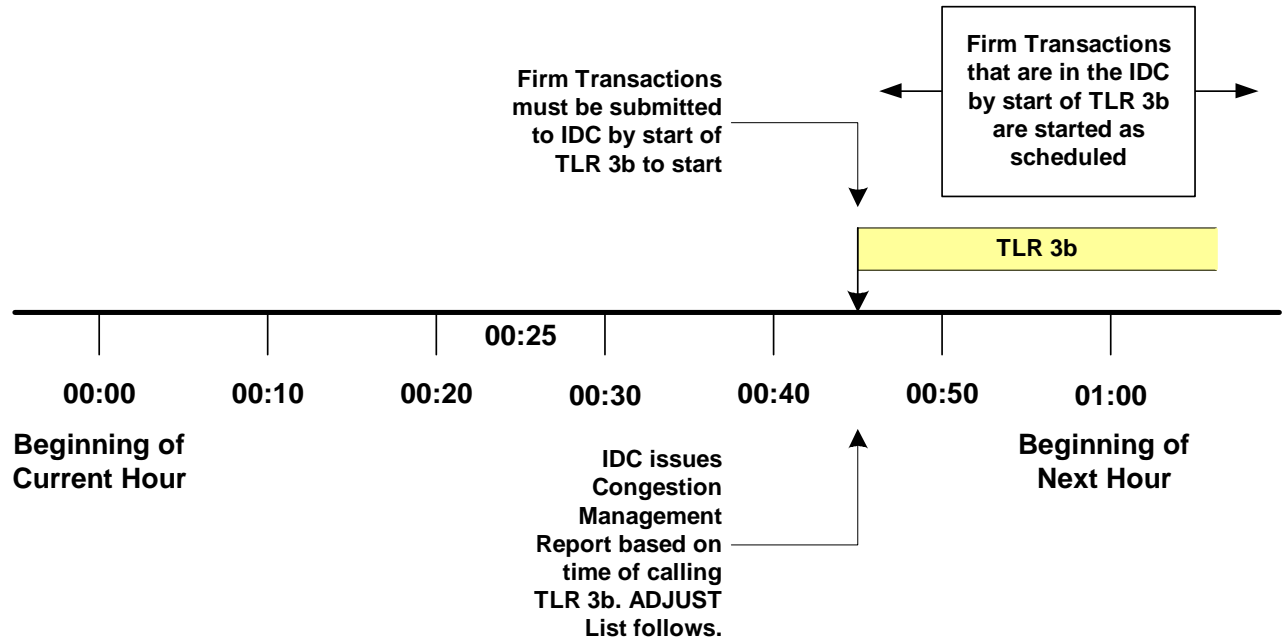
**1.18.11** Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.



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.

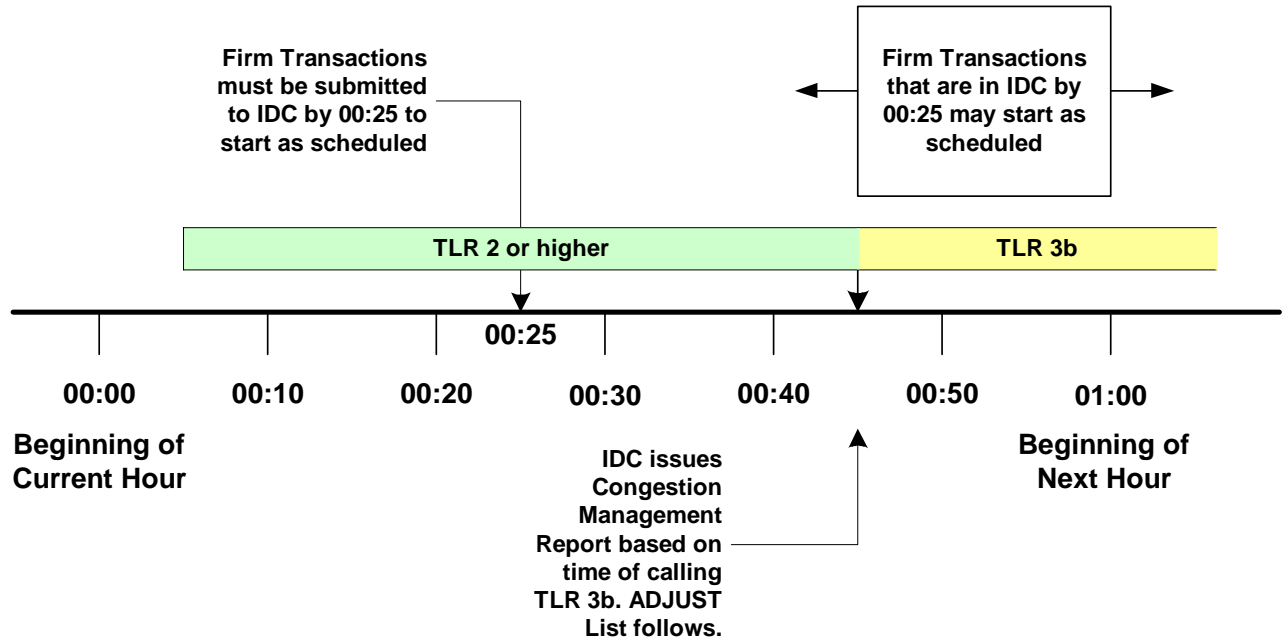
4. All existing or new INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority INTERCHANGE TRANSACTIONS using Non-firm Point-to-Point 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 SYSTEM OPERATING LIMIT or INTERCONNECTION RELIABILITY OPERATING LIMIT Violation is mitigated, the RELIABILITY AUTHORITY 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.

**1.18.12 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.**



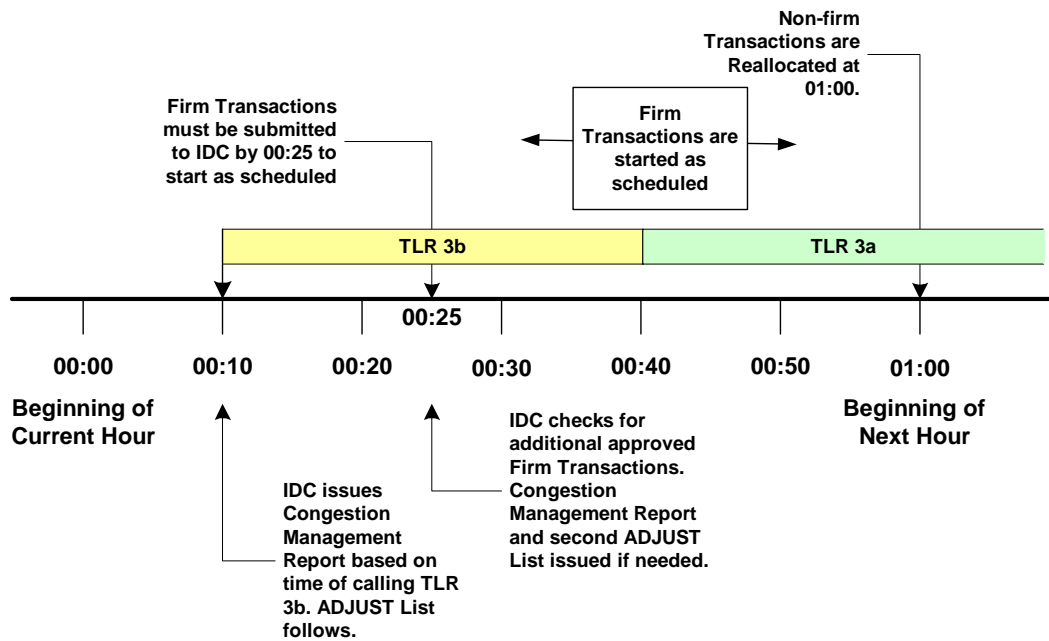
1. The IDC will examine the current hour (00) and next hour (01) for all INTERCHANGE TRANSACTIONS.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service 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.)

**1.18.13** 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 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.

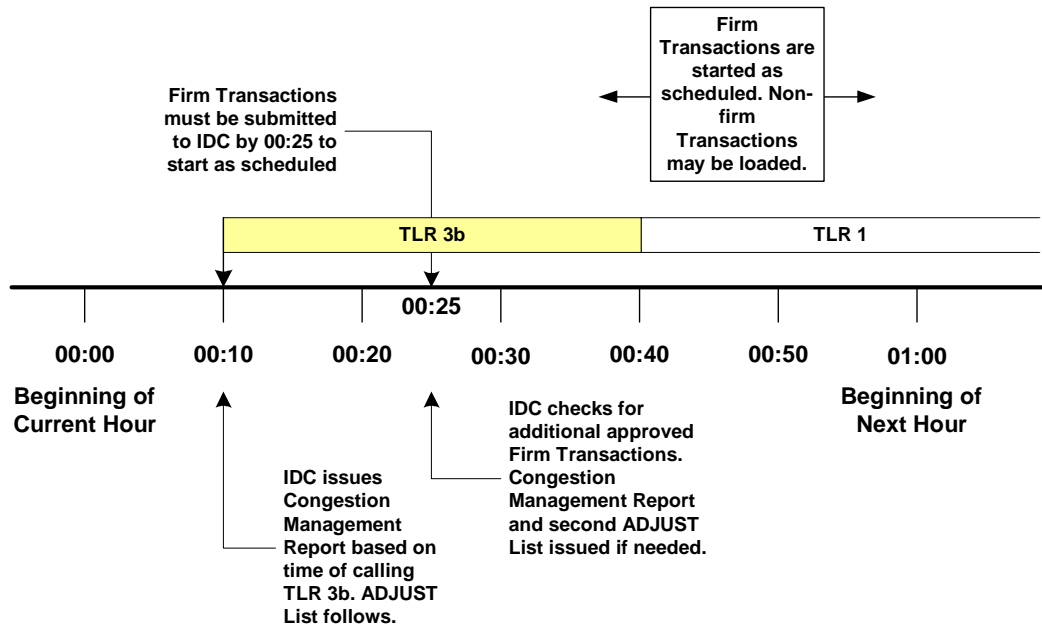
**1.18.14** Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.



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.



**1.18.15** 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.