



May 5, 2009

VIA ELECTRONIC FILING

Ms. Erica Hamilton, Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
V6Z 2N3

Re: *North American Electric Reliability Corporation*

Dear Ms. Hamilton:

The North American Electric Reliability Corporation (“NERC”) hereby submits this notice of 15 Reliability Standards that contains errata changes from the versions previously submitted. These proposed Reliability Standards, contained in **Exhibit A** to this petition, are:

- BAL-001-0.1a - Real Power Balancing Control Performance
- BAL-003-0.1b - Frequency Response and Bias
- BAL-005-0.1b – Automatic Generation ControlBAL-006-1.1 – Inadvertent Interchange
- COM-001-1.1 – Telecommunications
- EOP-002-2.1 - Capacity and Energy Emergencies
- IRO-001-1.1 - Reliability Coordination — Responsibilities and Authorities
- MOD-006-0.1 - Procedures for Use of CBM Values
- MOD-016-1.1 - Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand Side Management
- MOD-017-0.1 - Aggregated Actual and Forecast Demands and Net Energy for Load
- MOD-019-0.1 - Forecasts of Interruptible Demands and DCLM
- PRC-016-0.1 - System Protection System Misoperations
- TOP-005-1.1 – Operational Reliability Information

- TPL-001-0.1 - System Performance Under Normal Conditions
- VAR-002-1.1a - Generator Operation for Maintaining Network Voltage Schedules

These proposed Reliability Standards were approved by the NERC Board of Trustees on October 29, 2008. These standards will supersede the existing versions of the standards approved by the Federal Energy Regulatory Commission.

NERC's notice consists of the following:

- This transmittal letter;
- A table of contents for the entire notice;
- Reliability Standards submitted (**Exhibit A**);
- NERC Standards Committee Errata Procedure (**Exhibit B**); and
- Comments Received to the Errata Posting (**Exhibit C**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael
Rebecca J. Michael

*Attorney for North American Electric
Reliability Corporation*

**BEFORE THE
BRITISH COLUMBIA UTILITIES COMMISSION
OF THE PROVINCE OF BRITISH COLUMBIA**

**NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)**

**NOTICE OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
OF 15 RELIABILITY STANDARDS THAT CONTAIN
ERRATA CHANGES**

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TABLE OF CONTENTS

I.	Introduction	1
II.	Notices and Communications	2
III.	Background:	2
	Exhibit A – Reliability Standards Proposed	
	Exhibit B – NERC Standards Committee Errata Procedure	
	Exhibit C – Comments Received to the Errata Posting	

I. INTRODUCTION

The North American Electric Reliability Corporation (“NERC”) hereby submits notice of 15 Reliability Standards that contain errata changes to the versions previously submitted.

Because these errata changes do not change substantively the content or intent of the existing Reliability Standards, NERC developed these proposed Reliability Standards using an errata approval process developed by its Standards Committee rather than pursuing approval through the use of the *Reliability Standard Development Procedure, Version 6.1*, set forth in Appendix 3A to the NERC Rules of Procedure.

On October 29, 2008, the NERC Board of Trustees approved the errata changes to 15 Reliability Standards proposed by NERC.¹ **Exhibit A** to this filing sets forth the 15 proposed Reliability Standards.

Exhibit B contains the NERC Standards Committee Errata Approval Procedure. This is included for informational purposes only and NERC is not requesting approval of this procedure. **Exhibit C** contains the comments received and the response to those comments associated with the industry posting of the errata changes identified in **Exhibit A**.

NERC filed these errata changes to the 15 Reliability Standards with the Federal Energy Regulatory Commission (“FERC”) and is filing them with the other applicable governmental authorities in Canada.

¹ The NERC Board of Trustees also approved proposed errata to MOD-015-0.1 - Development of Dynamic System Models. NERC is not submitting this proposed Reliability Standard.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

Each of the proposed Reliability Standards set out in **Exhibit A** was initially developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*. Since the filing of those Reliability Standards, NERC has identified what it considers a number of errata type modifications.

The NERC Standards Committee developed and approved a process, contained in **Exhibit B** to this filing, to administer the processing of errata changes to NERC standards. The purpose of this additional procedure is to gain confirmation from the industry of the Standards Committee's initial view that the errata changes should be made. In the view of the Committee, errata can be a misspelled word, an incorrect reference to a requirement or measure, or an error, such as a missing word, *etc.*, that, when added or corrected, does not change the scope or technical content of the standard. When notified of a proposed errata modification, the NERC Standards Committee determines if the proposed modification qualifies as errata. The errata changes are

presented for industry notice and comment for a thirty day comment period. The Standards Committee responds to the comments received and ultimately recommends if the proposed errata change should be presented for NERC Board of Trustees approval. Each of the errata changes noted in this filing were processed in accordance with this procedure and approved by the NERC Board on October 29, 2008.

Since it submitted notice of its compendium of Reliability Standards, from its initial April 4, 2006 request to the present, NERC has identified a number of changes to the standards that it considers to be non-substantive errors, and that have been deemed, therefore, to be errata. NERC assembled these various errata changes and developed clean and red-lined copies of the standard changes containing the errata and submitted the errata for industry review and comment through the Standards Committee errata process from July 2, 2008 through July 31, 2008. With the exception of the requested errata modification to EOP-004-1 – Disturbance Reporting,² each of the 15 Reliability Standards included in this filing were successfully processed using this procedure and were adopted by the NERC Board of Trustees at its October 29, 2008 meeting.

In addition, NERC notes its new standard version approach recognizes standard errata changes. When a NERC Reliability Standard is processed and adopted by the NERC Board of Trustees containing errata changes, NERC will not change the original version number *per se*. NERC will, however, add a supplemental version mechanism to supplement the current version on file that takes the form of a “.1” for the first errata

² Suggested errata changes to EOP-004-1 were presented for industry review and comment. Per industry feedback, the changes suggested to EOP-004-1 were determined to be more substantive and did not fit the definition of errata. In accordance with the Standards Committee errata procedure, these changes were not carried forward and are being maintained by NERC for consideration in a future standard drafting effort that addresses the standard. Industry comments are included in the comment information contained in Exhibit C.

change, “.2” for the second, and so on. For example, the original version of Reliability Standard BAL-006 is BAL-006-1 and the first errata change has been designated as BAL-006-1.1.

Respectfully submitted,

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Exhibit A

Reliability Standards Proposed for Approval

Reliability Standards Errata Sheet

Standard Number	Standard Title	Section Number	Description of Correction	Date Revised
BAL-001-0a	Real Power Balancing Control Performance	Sections A, F;	<ul style="list-style-type: none"> In Section A.2., Added "a" to end of standard number. The "a" was mistakenly omitted when the BAL-001-0a was filed with FERC. In Section F, corrected automatic numbering from "2" to "1" and added parenthesis to "(October 23, 2007)." 	01/16/08
BAL-003-0a	Frequency Response and Bias	Section F;	<ul style="list-style-type: none"> Section F: added "1."; 	01/16/08
BAL-005-0a		Sections A, F;	<ul style="list-style-type: none"> In Section A.2., Added "a" to end of standard number. The "a" was mistakenly omitted when the BAL-005-0a was filed with FERC. Section F: added "1."; 	01/16/08
BAL-006-1	Inadvertent Interchange	Effective Date	Removed "This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first."	05/09/07
COM-001-1	Telecommunications	R1.	Added the word "for" between "facilities" and "the exchange." Inadvertently omitted.	04/06/07
EOP-002-1 (carried forward to EOP-002-2)	Capacity and Energy Emergencies	R7.	Changed R7. to refer to "Requirement 6" instead of "Requirement 7."	09/19/06
EOP-002-2	Capacity and Energy Emergencies	A.4. Applicability	Corrected numbering in Section A.4. "Applicability."	01/24/07
EOP-002-2	Capacity and Energy Emergencies	A.4. Applicability	Added inadvertently omitted "4.3. Load-Serving Entity" to Applicability Section.	10/01/07
FAC 010-1, 011-1, 014-1 Implementation Plan	Implementation Plan	Page 2	Reference corrected in TOP-004 discussion: R6.1 and R6.5 are to be retired coincident with implementation of FAC-014, not FAC-011.	06/27/08
IRO-001-1	Reliability Coordination — Responsibilities and Authorities	D.1.3.	Changed "Distribution Provider" to Transmission Service Provider." Distribution Provider was inappropriately listed in the Compliance – Data Retention section.	11/19/06
IRO-001-1	Reliability Coordination — Responsibilities and Authorities	Effective Date	Removed "Proposed" from Effective Date label	10/29/08
MOD-006-0	Procedures for Use of CBM Values	Requirement R1	Replaced "preservation" with "reservation" in R1.	09/17/07
MOD-006-0	Procedures for Use of CBM Values	Measure M1	Replaced "preservation" with "reservation" in Measure M1.	10/29/08
MOD-015-0	Development of Dynamic System Models	C. Measure M1.	Corrected typo in Section M1. — removed reference to Requirement R3 as it does not exist.	01/26/07

Standard Number	Standard Title	Section Number	Description of Correction	Date Revised
MOD-016-1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	R2. and R3.	Corrected sequential numbering problem in Sections R2. and R3.	01/26/07
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	R1. and D1.2.	Revised R1 and D1.2. to reflect update in version from "MOD-016-0_R1" to MOD-016-1_R1."	05/18/07
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	R1. and D1.2.	Revised R1 and D1.2. to reflect update in version from "MOD-016-0_R1" to MOD-016-1_R1."	07/24/07
PRC-016-0	Special Protection System Misoperations	C. Measure M1.	Change erroneous reference in Measure 1 from "PRC-016-0_R1" to "PRC-012-0_R1."	07/03/07
TOP-005-1	Operational Reliability Information	Compliance Section D.2.1 and D.2.4	Revised D.2.1 and D.2.4 reference "Requirements R1 to R5" "to Requirements R1 to R4."	10/23/07
TPL-001-0	System Performance Under Normal Conditions	C. Measure M1.	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	07/24/07
VAR-002-1a	Generator Operation for Maintaining Network voltage Schedules	Sections A, F; Appendix 1	<ul style="list-style-type: none"> In Section A.2., Added "a" to end of standard number. Section F: added "1." and date of BOT approval. 	01/16/08

A. Introduction

1. **Title:** Real Power Balancing Control Performance
2. **Number:** BAL-001-0.1a
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:**
 - 4.1. Balancing Authorities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority’s Area Control Error (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 ϵ_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right] \leq \epsilon_1^2 \text{ or } \frac{AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right]}{\epsilon_1^2} \leq 1$$

The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- 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 correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

- R2.** Each Balancing Authority shall operate such that its 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 L_{10} .

$$AVG_{10\text{-minute}} (ACE_i) \leq L_{10}$$

where:

$$L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10} , is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

- R3.** Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.
- R4.** Any 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).

C. Measures

- M1.** Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

$$CPS1 = (2 - CF) * 100\%$$

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:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ 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.

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.

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right)}{-10B}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority’s clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Standard BAL-001-0.1a — Real Power Balancing Control Performance

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority 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., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-}i})(n_{(\text{one-minute samples in month-}i)})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month-}i)}]}$$

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 CPS1.

- M2.** Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10} . ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes
= 0 if

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

= 1 if

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 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.

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.

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 CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority 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 (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

Standard BAL-001-0.1a — Real Power Balancing Control Performance

2.4. Level 4: The Balancing Authority Area’s value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area’s value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area’s value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area’s value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area’s value of CPS2 is less than 75%.

E. Regional Differences

1. The [ERCOT Control Performance Standard 2 Waiver](#) approved November 21, 2002.

F. Associated Documents

1. Appendix 2 – Interpretation of Requirement R1 (October 23, 2007).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2.	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added “a” to end of standard number. In Section F, corrected automatic numbering from “2” to “1” and removed “approved” and added parenthesis to “(October 23, 2007).”	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to “0.1a”	Errata

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10} .	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

BAL-001-0

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (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 ϵ_{12} is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

A. Introduction

1. **Title:** Real Power Balancing Control Performance
2. **Number:** BAL-001-0.1a
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:**
 - 4.1. Balancing Authorities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority’s Area Control Error (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 ϵ_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right] \leq \epsilon_1^2 \text{ or } \frac{AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right]}{\epsilon_1^2} \leq 1$$

The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- 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 correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

- R2.** Each Balancing Authority shall operate such that its 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 L_{10} .

$$AVG_{10\text{-minute}} (ACE_i) \leq L_{10}$$

where:

$$L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10} , is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

- R3.** Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.
- R4.** Any 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).

C. Measures

- M1.** Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

$$CPS1 = (2 - CF) * 100\%$$

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:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ 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.

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.

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left(\sum ACE_{\text{sampling cycles in clock-minute}} \right)}{n_{\text{sampling cycles in clock-minute}} - 10B}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority’s clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority’s ACE and of the respective Interconnection’s Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority 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., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-}i})(n_{(\text{one-minute samples in month-}i)})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month-}i)}]}$$

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 CPS1.

- M2.** Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10} . ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if}$$

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 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.

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.

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 CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority 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 (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

Standard BAL-001-0.1a — Real Power Balancing Control Performance

2.4. **Level 4:** The Balancing Authority Area’s value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. **Level 1:** The Balancing Authority Area’s value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. **Level 2:** The Balancing Authority Area’s value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. **Level 3:** The Balancing Authority Area’s value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. **Level 4:** The Balancing Authority Area’s value of CPS2 is less than 75%.

E. Regional Differences

1. The [ERCOT Control Performance Standard 2 Waiver](#) approved November 21, 2002.

F. Associated Documents

2.1. Appendix 2 – Interpretation of Requirement R1 ~~approved~~ (October 23, 2007).

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Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2.	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	<u>In Section A.2., Added “a” to end of standard number.</u> <u>In Section F, corrected automatic numbering from “2” to “1” and removed “approved” and added parenthesis to “(October 23, 2007).”</u>	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
<u>0.1a</u>	<u>October 29, 2008</u>	<u>Board approved errata changes; updated version number to “0.1a”</u>	<u>Errata</u>

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

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CPS1 DATA	Description	Retention Requirements
ϵ_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ϵ_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10} .	Retain the values of V used in CPS2 calculation.
ϵ_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ϵ_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

BAL-001-0

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (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 ϵ_{12} is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

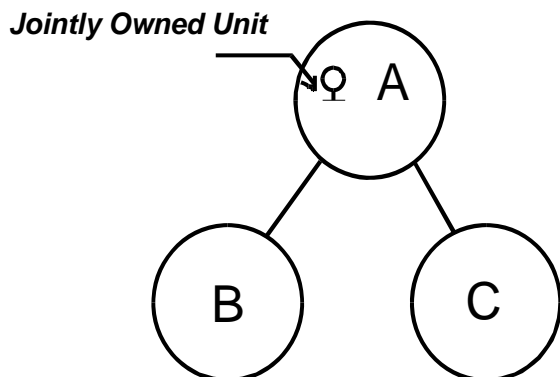
A. Introduction

- 1. Title:** **Frequency Response and Bias**
- 2. Number:** BAL-003-0.1b
- 3. Purpose:**
This standard provides a consistent method for calculating the Frequency Bias component of ACE.
- 4. Applicability:**
 - 4.1.** Balancing Authorities.
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

- 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 the Frequency Response of the Balancing Authority Area.
 - R1.1.** 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.
 - R1.2.** Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.
- R2.** Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:
 - R2.1.** 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 for several Disturbances during on-peak hours.
 - R2.2.** The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable 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.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.
- R4.** Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.
 - R4.1.** Fixed schedules for Jointly Owned Units mandate that 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). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R5. 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.

R5.1. 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.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority’s response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R3 (October 23, 2007).
2. Appendix 2 – Interpretation of Requirements R2, R2.2, R5, and R5.1 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R3 approved by BOT on October 23, 2007	Addition

Standard BAL-003-0.1b — Frequency Response and Bias

0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Added Appendix 2 – Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata

Appendix 1

Interpretation of Requirement 3

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 3 of BAL-003-0?*

Interpretation:

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

BAL-003-0

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

Appendix 2

Interpretation of Requirements R2, R2.2, R5, R5.1

Request: *ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings.*

Interpretation:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. 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 for several Disturbances during on-peak hours.

R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable 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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

R5. 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.

R5.1. 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.

A. Introduction

1. Title: Frequency Response and Bias

2. Number: BAL-003-0.1b

3. Purpose:

This standard provides a consistent method for calculating the Frequency Bias component of ACE.

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

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 the Frequency Response of the Balancing Authority Area.

R1.1. 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.

R1.2. Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. 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 for several Disturbances during on-peak hours.

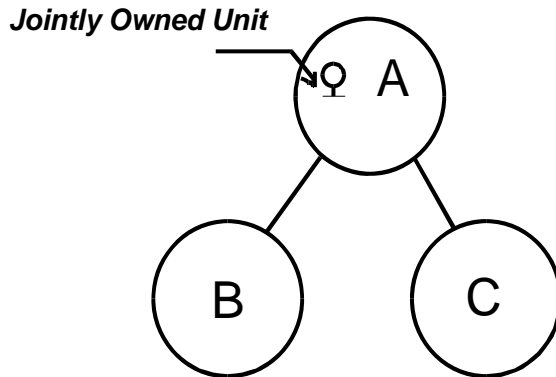
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

R4. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

R4.1. Fixed schedules for Jointly Owned Units mandate that 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). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R5. 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.

R5.1. 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.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority’s response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R3 (October 23, 2007).
2. Appendix 2 – Interpretation of Requirements R2, R2.2, R5, and R5.1 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R3 approved by BOT on October 23, 2007	Addition

Standard BAL-003-0.1b — Frequency Response and Bias

0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Added Appendix 2 – Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
<u>0.1b</u>	<u>October 29, 2008</u>	<u>BOT approved errata changes; updated version number to “0.1b”</u>	<u>Errata</u>

Appendix 1

Interpretation of Requirement 3

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 3 of BAL-003-0?*

Interpretation:

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

BAL-003-0

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

Appendix 2

Interpretation of Requirements R2, R2.2, R5, R5.1

Request: *ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings.*

Interpretation:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. 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 for several Disturbances during on-peak hours.

R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable 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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

R5. 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.

R5.1. 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.

A. Introduction

1. Title: Automatic Generation Control

2. Number: BAL-005-0.1b

3. Purpose:

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. Applicability:

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

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.

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 Intermediate Balancing Authorities.

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.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's 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 Coordinator.

R7. 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.

- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** 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%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (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.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** 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 megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** 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 the Anti-aliasing Filters of Tie Lines.
- R12.3.** 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.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour 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 (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** 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 ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** 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.
- R16.** 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 coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

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

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** 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 Error.
- 1.1.2.** 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 Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

- 1.3.1.** 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.
- 1.3.2.** 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 Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata

Appendix 1

Request: PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- Only equipment within the operations control room
- Only equipment that provides values used to calculate AGC ACE
- Only equipment that provides values to its SCADA system
- Only equipment owned or operated by the BA
- Only to new or replacement equipment
- To all equipment that a BA owns or operates

BAL-005-1

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

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

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation:

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. **Title:** Automatic Generation Control

2. **Number:** BAL-005-0.1b

3. **Purpose:**

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

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.

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 Intermediate Balancing Authorities.

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.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's 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 Coordinator.

R7. 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.

- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** 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%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (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.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** 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 megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** 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 the Anti-aliasing Filters of Tie Lines.
- R12.3.** 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.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour 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 (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** 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 ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** 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.
- R16.** 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 coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

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

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** 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 Error.
- 1.1.2.** 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 Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

- 1.3.1.** 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.
- 1.3.2.** 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 Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
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<u>0.1b</u>	<u>October 29, 2008</u>	<u>BOT approved errata changes; updated version number to “0.1b”</u>	

Appendix 1

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BAL-005-1

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

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
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Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation:

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. Title: Inadvertent Interchange

2. Number: BAL-006-1.1

3. Purpose:

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

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: Immediately after approval of applicable regulatory authorities

B. Requirements

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

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

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

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

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

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

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

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

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

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

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

- 1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).
- 1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.
- 1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.
- 1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority’s Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.
- 1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities’ monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Levels of Non Compliance

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

E. Regional Differences

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	April 6, 2006	Added following to “Effective Date:” and footer This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
1	May 2, 2006	Adopted by Board of Trustees	Revised
1	May 9, 2007	Removed “This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.” From the “Effective Date.” and footer	Correction

Standard BAL-006-1.1 — Inadvertent Interchange

1.1	October 29, 2008	BOT adopted errata changes; updated version number to 1.1	Errata
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A. Introduction

- 1. **Title:** Inadvertent Interchange
- 2. **Number:** BAL-006-1.1
- 3. **Purpose:**

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

4. Applicability:

4.1. Balancing Authorities.

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

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B. Requirements

- R1.** Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.
- R2.** Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.
- R3.** Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
- R4.** Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:
 - R4.1.** Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:
 - R4.1.1.** The hourly values of Net Interchange Schedule.
 - R4.1.2.** The hourly integrated megawatt-hour values of Net Actual Interchange.
 - R4.2.** Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
 - R4.3.** A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).
- R5.** Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

C. Measures

Adopted by NERC Board of Trustees: ~~May 2006~~ **October 29, 2006**
~~Effective Date: May 1, 2006. This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~

None specified.

D. Compliance

1. Compliance Monitoring Process

- 1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).
- 1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.
- 1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.
- 1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority’s Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.
- 1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities’ monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Levels of Non Compliance

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

E. Regional Differences

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<u>1</u>	<u>April 6, 2006</u>	<u>Added following to “Effective Date:” and footer This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.</u>	<u>Errata</u>
<u>1</u>	<u>May 2, 2006</u>	<u>Adopted by Board of Trustees</u>	<u>Revised</u>
<u>1</u>	<u>May 9, 2007</u>	<u>Removed “This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.” From the “Effective</u>	<u>Correction</u>

Adopted by NERC Board of Trustees: ~~May 2~~**October 29, 2006**~~2008~~
~~Effective Date: May 1, 2006. This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~

Standard BAL-006-1.1 — Inadvertent Interchange

		<u>Date.” and footer</u>	
<u>1.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to 1.1 and changed effective date</u>	<u>Errata</u>

Adopted by NERC Board of Trustees: ~~May 2006~~October 29, 2006
Effective Date: ~~May 1, 2006~~. This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.

A. Introduction

1. **Title:** **Telecommunications**
2. **Number:** COM-001-1.1
3. **Purpose:** Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
 - 4.4. NERCNet User Organizations.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:
 - R1.1. Internally.
 - R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
 - R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
 - R1.4. Where applicable, these facilities shall be redundant and diversely routed.
- R2. Each Reliability Coordinator, 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.
- R3. Each Reliability Coordinator, 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 area and with other areas.
- R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.

- R5.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.
- R6.** Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, “NERCNet Security Policy.”

C. Measures

- M1.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include, but is not limited to communication facility test-procedure documents, records of testing, and maintenance records for communication facilities or equivalent that will be used to confirm that it manages, alarms, tests and/or actively monitors vital telecommunications facilities. (Requirement 2 part 1)
- M2.** The Reliability Coordinator, Transmission Operator or Balancing Authority shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent, that will be used to determine compliance to Requirement 4.
- M3.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request its current operating instructions and procedures, either electronic or hard copy that will be used to confirm that it meets Requirement 5.
- M4.** The NERCnet User Organization shall have and provide upon request evidence that could include, but is not limited to documented procedures, operator logs, voice recordings or transcripts of voice recordings, electronic communications, etc that will be used to determine if it adhered to the (User Accountability and Compliance) requirements in Attachment 1-COM-001. (Requirement 6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations

Regional Reliability Organizations shall be responsible for compliance monitoring of all other entities

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1 each Reliability Coordinator, Transmission Operator, Balancing Authority shall keep evidence of compliance for the previous two calendar years plus the current year.

For Measure 2 each Reliability Coordinator, Transmission Operator, and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 3, each Reliability Coordinator, Transmission Operator, Balancing Authority shall have its current operating instructions and procedures to confirm that it meets Requirement 5.

For Measure 4, each Reliability Coordinator, Transmission Operator, Balancing Authority and NERCnet User Organization shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

Attachment 1-COM-001— NERCnet Security Policy

2. Levels of Non-Compliance for Transmission Operator, Balancing Authority or Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

2.3.1 The Transmission Operator, Balancing Authority or Reliability Coordinator used a language other than English without agreement as specified in R4.

2.3.2 There are no written operating instructions and procedures to enable continued operation of the system during the loss of telecommunication facilities as specified in R5.

2.4. Level 4: Telecommunication systems are not actively monitored, tested, managed or alarmed as specified in R2.

3. Levels of Non-Compliance — NERCnet User Organization

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: Did not adhere to the requirements in Attachment 1-COM-001, NERCnet Security Policy.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 6, 2007	Requirement 1, added the word “for” between “facilities” and “the exchange.”	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata

Attachment 1-COM-001— 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.
- To establish connectivity guidelines for 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, are 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.

Responsibilities

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 Reliability Coordinator Information System 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.

A. Introduction

1. **Title:** **Telecommunications**
2. **Number:** COM-001-1.1
3. **Purpose:** Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
 - 4.4. NERCNet User Organizations.
5. **Effective Date:** ~~_____~~ Immediately after approval of applicable regulatory authorities January 1, 2007

B. Requirements

- R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities **for** the exchange of Interconnection and operating information:
 - R1.1. Internally.
 - R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
 - R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
 - R1.4. Where applicable, these facilities shall be redundant and diversely routed.
- R2. Each Reliability Coordinator, 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.
- R3. Each Reliability Coordinator, 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 area and with other areas.
- R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.

- R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.
- R6. Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, “NERCNet Security Policy.”

C. Measures

- M1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include, but is not limited to communication facility test-procedure documents, records of testing, and maintenance records for communication facilities or equivalent that will be used to confirm that it manages, alarms, tests and/or actively monitors vital telecommunications facilities. (Requirement 2 part 1)
- M2. The Reliability Coordinator, Transmission Operator or Balancing Authority shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent, that will be used to determine compliance to Requirement 4.
- M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request its current operating instructions and procedures, either electronic or hard copy that will be used to confirm that it meets Requirement 5.
- M4. The NERCnet User Organization shall have and provide upon request evidence that could include, but is not limited to documented procedures, operator logs, voice recordings or transcripts of voice recordings, electronic communications, etc that will be used to determine if it adhered to the (User Accountability and Compliance) requirements in Attachment 1-COM-001. (Requirement 6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations

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1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
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- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1 each Reliability Coordinator, Transmission Operator, Balancing Authority shall keep evidence of compliance for the previous two calendar years plus the current year.

For Measure 2 each Reliability Coordinator, Transmission Operator, and Balancing Authority shall keep 90 days of historical data (evidence).

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1.4. Additional Compliance Information

Attachment 1-COM-001— NERCnet Security Policy

2. Levels of Non-Compliance for Transmission Operator, Balancing Authority or Reliability Coordinator

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

2.3.1 The Transmission Operator, Balancing Authority or Reliability Coordinator used a language other than English without agreement as specified in R4.

2.3.2 There are no written operating instructions and procedures to enable continued operation of the system during the loss of telecommunication facilities as specified in R5.

2.4. **Level 4:** Telecommunication systems are not actively monitored, tested, managed or alarmed as specified in R2.

3. **Levels of Non-Compliance — NERCnet User Organization**

3.1. **Level 1:** Not applicable.

3.2. **Level 2:** Not applicable.

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** Did not adhere to the requirements in Attachment 1-COM-001, NERCnet Security Policy.

E. Regional Differences

None Identified.

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0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	<u>Revised</u>
<u>1</u>	<u>April 6, 2007</u>	<u>Requirement 1, added the word “for” between “facilities” and “the exchange.”</u>	<u>Errata</u>
<u>1.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “1.1”</u>	<u>Errata</u>

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- 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 Reliability Coordinator Information System 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.

A. Introduction

1. **Title:** Capacity and Energy Emergencies
2. **Number:** EOP-002-2.1
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
 - 4.1. Balancing Authorities.
 - 4.2. Reliability Coordinators.
 - 4.3. Load-Serving Entities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. Each Balancing Authority and Reliability Coordinator 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 capacity and energy emergencies.
- R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
- R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
- 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.
- R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. 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.
- R6. 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:
 - R6.1. Loading all available generating capacity.
 - R6.2. Deploying all available operating reserve.
 - R6.3. Interrupting interruptible load and exports.
 - R6.4. Requesting emergency assistance from other Balancing Authorities.
 - R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

- R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.
- R7.** Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:
 - R7.1.** Manually shed firm load without delay to return its ACE to zero; and
 - R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”
- R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
- R9.** When a Transmission Service Provider expects to 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) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):
 - R9.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.
 - R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.
 - R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.
 - R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

- M1.** Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.
- M2.** If a Reliability Coordinator or Balancing Authority implements its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency

conditions were in conformance with its Capacity and Energy Emergency Plan.
(Requirement 2)

- M3.** If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.
- M4.** If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.
- M5.** If a Transmission Service Provider expects to 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), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 4 and 5 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator:

2.1. Level 1: Did not submit the report to NERC as required in R9.2.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate. (R2)

2.4.2 There is no evidence an Emergency Alert was issued as specified in R8

2.4.3 Failed to comply with R9.3 or R9.4

2.4.4 Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3. Levels of Non-Compliance for a Balancing Authority:

3.1. Level 1: Not applicable.

3.2. Level 2: Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities when in an operating Capacity or Energy Emergency (R3).

3.4.2 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate (R2).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata

Attachment 1-EOP-002-2.1 Energy Emergency Alerts

Introduction

This Attachment 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 Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

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

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. Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated only by a Reliability Coordinator 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.

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

- When 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 the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. Notification. A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency

Alerts. The Reliability Coordinators 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 reliability standards or power supply contracts.

The Reliability Coordinator 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 contracts¹.
 - Demand-side management.
 - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, 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 Coordinator shall post the declaration of the alert level along with the name of the

¹ For emergency, not economic, reasons.

Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

- 2.2 Declaration period.** The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.
- 2.3 Sharing information on resource availability.** A 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 Coordinators of the results.
- 2.4 Evaluating and mitigating transmission limitations.** The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their 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 websites 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 Coordinator.
- 2.4.3 Evaluating impact of current transmission loading relief events.** The Reliability Coordinators 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 reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.
- 2.4.4 Initiating inquiries on reevaluating SOLs and IROLs.** The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.
- 2.5 Coordination of emergency responses.** The Reliability Coordinator 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 demand-side management 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 Coordinators 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 website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators 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 SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the

reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs 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 Coordinator 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 Coordinator shall use its best efforts to ensure that revising SOLs or IROLs 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 SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator 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 Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator 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 its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

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 Coordinator 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:

A. Introduction

1. **Title:** Capacity and Energy Emergencies
2. **Number:** EOP-002-2.1
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
 - 4.1. Balancing Authorities.
 - 4.2. Reliability Coordinators.
 - 4.3. Load-Serving Entities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities January 1, 2007

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B. Requirements

- R1. Each Balancing Authority and Reliability Coordinator 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 capacity and energy emergencies.
- R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
- R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
- 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.
- R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. 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.
- R6. 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:
 - R6.1. Loading all available generating capacity.
 - R6.2. Deploying all available operating reserve.
 - R6.3. Interrupting interruptible load and exports.
 - R6.4. Requesting emergency assistance from other Balancing Authorities.

- R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and
- R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.
- R7.** Once the Balancing Authority has exhausted the steps listed in Requirement **76**, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:
 - R7.1.** Manually shed firm load without delay to return its ACE to zero; and
 - R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”
- R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
- R9.** When a Transmission Service Provider expects to 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) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):
 - R9.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.
 - R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.
 - R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.
 - R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

- M1.** Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.
- M2.** If a Reliability Coordinator or Balancing Authority implements its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent

evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

- M3.** If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.
- M4.** If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.
- M5.** If a Transmission Service Provider expects to 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), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an

extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 4 and 5 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator:

2.1. **Level 1:** Did not submit the report to NERC as required in R9.2.

2.2. **Level 2:** Not applicable.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate. (R2)

2.4.2 There is no evidence an Emergency Alert was issued as specified in R8

2.4.3 Failed to comply with R9.3 or R9.4

2.4.4 Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3. Levels of Non-Compliance for a Balancing Authority:

3.1. **Level 1:** Not applicable.

3.2. **Level 2:** Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities when in an operating Capacity or Energy Emergency (R3).

3.4.2 One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate (R2).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<u>1</u>	<u>September 19, 2006</u>	<u>Changes R7. to refer to “Requirement 6” instead of “Requirement 7”</u>	<u>Errata</u>
2	November 1, 2006	Adopted by Board of Trustees	<u>Revised</u>
<u>2</u>	<u>November 1, 2006</u>	<u>Corrected numbering in Section A.4. “Applicability.”</u>	<u>Errata</u>
<u>2</u>	<u>October 1, 2007</u>	<u>Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities</u>	<u>Errata</u>
<u>2.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “2.1”</u>	<u>Errata</u>

Attachment 1-EOP-002-~~0~~2.1
Energy Emergency Alerts

Introduction

This Attachment 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 Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

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

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. Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated only by a Reliability Coordinator 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.

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

- When 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 the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. Notification. A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency

Alerts. The Reliability Coordinators 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 reliability standards or power supply contracts.

The Reliability Coordinator 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 contracts¹.
 - Demand-side management.
 - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, 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 Coordinator shall post the declaration of the alert level along with the name of the

¹ For emergency, not economic, reasons.

Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

- 2.2 Declaration period.** The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.
- 2.3 Sharing information on resource availability.** A 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 Coordinators of the results.
- 2.4 Evaluating and mitigating transmission limitations.** The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their 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 websites 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 Coordinator.
- 2.4.3 Evaluating impact of current transmission loading relief events.** The Reliability Coordinators 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 reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.
- 2.4.4 Initiating inquiries on reevaluating SOLs and IROLs.** The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.
- 2.5 Coordination of emergency responses.** The Reliability Coordinator 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 demand-side management 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 Coordinators 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 website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators 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 SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the

reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs 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 Coordinator 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 Coordinator shall use its best efforts to ensure that revising SOLs or IROLs 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 SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator 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 Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator 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 its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

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 Coordinator 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:

A. Introduction

1. **Title:** **Reliability Coordination — Responsibilities and Authorities**
2. **Number:** IRO-001-1.1
3. **Purpose:** Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Regional Reliability Organizations.
 - 4.3. Transmission Operator.
 - 4.4. Balancing Authorities.
 - 4.5. Generator Operators.
 - 4.6. Transmission Service Providers.
 - 4.7. Load-Serving Entities.
 - 4.8. Purchasing-Selling Entities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.
- R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.
- R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
- R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.

- R5.** The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.
- R6.** The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.
- R7.** The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.
- R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.
- R9.** The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.

C. Measures

- M1.** Each Regional Reliability Organization shall have, and provide upon request, evidence that could include, but is not limited to signed agreements or other equivalent evidence that will be used to confirm that it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.
- M2.** Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to act as described in Requirement 3.
- M3.** The Reliability Coordinator shall have and provide upon request current formal operating agreements with entities that have been delegated any Reliability Coordinator tasks (Requirement 4 Part 1).
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, records of training sessions, monitoring procedures or other equivalent evidence that will be used to confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area (Requirement 4 Part 2 and Requirement 5).
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, records that show each operating person assigned to perform a Reliability Coordinator delegated task has a NERC Reliability Coordinator certification credential, or equivalent evidence confirming that delegated tasks were

carried out by NERC certified Reliability Coordinator operating personnel, as specified in Requirement 6.

- M6.** The Reliability Coordinator shall have and provide upon request as evidence, signed agreements with adjacent Reliability Coordinators that will be used to confirm that it will coordinate corrective actions in the event SOL and IROL mitigation actions within neighboring areas must be taken. (Requirement 7)
- M7.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, or other equivalent evidence that will be used to confirm that it did comply with the Reliability Coordinator's directives, or if for safety, equipment, regulatory or statutory requirements it could not comply, it informed the Reliability Coordinator immediately. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organization.

Regional Reliability Organizations shall be responsible for compliance monitoring of the Reliability Coordinators, Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities.

1.2. Compliance Monitoring Period and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force document for Measure 1.

Each Reliability Coordinator shall have its current, in-force documents or the latest copy of a record as evidence of compliance to Measures 2 through 6.

Each Transmission Operator, Generator Operator, Transmission Service Provider, and Load Serving Entity shall keep 90 days of historical data (evidence) for Measure 7.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance: for a Regional Reliability Organization:

2.1. Level 1: Not applicable

2.2. Level 2: Not applicable

2.3. Level 3: Not applicable

2.4. Level 4: Does not have evidence it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.

3. Levels of Non-Compliance for a Reliability Coordinator:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:

3.4.1 Does not have the authority to act as described in R3.

3.4.2 Does not have formal operating agreements with entities that have been delegated any Reliability Coordinator tasks, as specified in R4, Part 1.

3.4.3 Did not confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area and that they are being performed in a manner that complies with NERC and regional standards for the delegated tasks as per R4, Part 2.

3.4.4 Did not verify that delegated tasks are being carried out by NERC Reliability Coordinator certified staff as specified in R6.

3.4.5 Does not have agreements with adjacent Reliability Coordinators that confirm that they will coordinate corrective actions in the event SOL and IROL mitigation actions must be taken (R7).

4. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator directive for reasons other than safety, equipment, or regulatory or statutory requirements. (R8)

4.4.2 Did not inform the Reliability Coordinator immediately after it was determined that it could not follow a Reliability Coordinator directive. (R8)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes “Distribution Provider” to “Transmission Service Provider”	Errata
1.1	October 29, 2008	<ul style="list-style-type: none"> – Removed “Proposed” from effective date; – BOT adopted errata changes; updated version number to “1.1” 	Errata

A. Introduction

1. **Title:** Reliability Coordination — Responsibilities and Authorities
2. **Number:** IRO-001-1.1
3. **Purpose:** Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Regional Reliability Organizations.
 - 4.3. Transmission Operator.
 - 4.4. Balancing Authorities.
 - 4.5. Generator Operators.
 - 4.6. Transmission Service Providers.
 - 4.7. Load-Serving Entities.
 - 4.8. Purchasing-Selling Entities.
5. ~~(Proposed)~~ **Effective Date:** Immediately after approval of applicable regulatory authorities
January 1, 2007

B. Requirements

- R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.
- R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.
- R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
- R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.

- R5.** The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.
- R6.** The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.
- R7.** The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.
- R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.
- R9.** The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.

C. Measures

- M1.** Each Regional Reliability Organization shall have, and provide upon request, evidence that could include, but is not limited to signed agreements or other equivalent evidence that will be used to confirm that it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.
- M2.** Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to act as described in Requirement 3.
- M3.** The Reliability Coordinator shall have and provide upon request current formal operating agreements with entities that have been delegated any Reliability Coordinator tasks (Requirement 4 Part 1).
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, records of training sessions, monitoring procedures or other equivalent evidence that will be used to confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area (Requirement 4 Part 2 and Requirement 5).
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, records that show each operating person assigned to perform a Reliability Coordinator delegated task has a NERC Reliability Coordinator certification credential, or equivalent evidence confirming that delegated tasks were

carried out by NERC certified Reliability Coordinator operating personnel, as specified in Requirement 6.

- M6.** The Reliability Coordinator shall have and provide upon request as evidence, signed agreements with adjacent Reliability Coordinators that will be used to confirm that it will coordinate corrective actions in the event SOL and IROL mitigation actions within neighboring areas must be taken. (Requirement 7)
- M7.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, or other equivalent evidence that will be used to confirm that it did comply with the Reliability Coordinator's directives, or if for safety, equipment, regulatory or statutory requirements it could not comply, it informed the Reliability Coordinator immediately. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organization.

Regional Reliability Organizations shall be responsible for compliance monitoring of the Reliability Coordinators, Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities.

1.2. Compliance Monitoring Period and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force document for Measure 1.

Each Reliability Coordinator shall have its current, in-force documents or the latest copy of a record as evidence of compliance to Measures 2 through 6.

Each Transmission Operator, Generator Operator, ~~Distribution Provider~~ Transmission Service Provider, and Load Serving Entity shall keep 90 days of historical data (evidence) for Measure 7.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance: for a Regional Reliability Organization:

2.1. **Level 1:** Not applicable

2.2. **Level 2:** Not applicable

2.3. **Level 3:** Not applicable

2.4. **Level 4:** Does not have evidence it established one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries as described in Requirement 1.

3. Levels of Non-Compliance for a Reliability Coordinator:

3.1. **Level 1:** Not applicable.

3.2. **Level 2:** Not applicable.

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:

3.4.1 Does not have the authority to act as described in R3.

3.4.2 Does not have formal operating agreements with entities that have been delegated any Reliability Coordinator tasks, as specified in R4, Part 1.

3.4.3 Did not confirm that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area and that they are being performed in a manner that complies with NERC and regional standards for the delegated tasks as per R4, Part 2.

3.4.4 Did not verify that delegated tasks are being carried out by NERC Reliability Coordinator certified staff as specified in R6.

3.4.5 Does not have agreements with adjacent Reliability Coordinators that confirm that they will coordinate corrective actions in the event SOL and IROL mitigation actions must be taken (R7).

4. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity:

- 4.1. Level 1: Not applicable.
- 4.2. Level 2: Not applicable.
- 4.3. Level 3: Not applicable.
- 4.4. Level 4: There shall be a separate Level 4 non-compliance for every one of the following requirements that is in violation:
 - 4.4.1 Did not comply with a Reliability Coordinator directive for reasons other than safety, equipment, or regulatory or statutory requirements. (R8)
 - 4.4.2 Did not inform the Reliability Coordinator immediately after it was determined that it could not follow a Reliability Coordinator directive. (R8)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<u>1</u>	<u>November 1, 2006</u>	<u>Adopted by Board of Trustees</u>	<u>Revised</u>
<u>1</u>	<u>November 19, 2006</u>	<u>Changes “Distribution Provider” to “Transmission Service Provider”</u>	<u>Errata</u>
<u>1.1</u>	<u>October 29, 2008</u>	<ul style="list-style-type: none"> – <u>Removed “Proposed” from effective date;</u> – <u>BOT adopted errata changes; updated version number to “1.1”</u> 	<u>Errata</u>

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A. Introduction

1. **Title:** **Procedures for the Use of Capacity Benefit Margin Values**
2. **Number:** MOD-006-0.1
3. **Purpose:** To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users,
4. **Applicability:**
 - 4.1. Transmission Service Provider.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM reservation). The procedure shall include the following three components:
 - R1.1.** Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.
 - R1.2.** Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.
 - R1.3.** Describe the conditions under which CBM may be available as Non-Firm Transmission Service.
- R2.** Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..

C. Measures

- M1.** The Transmission Service Provider’s procedure for the use of CBM (scheduling of energy against a CBM reservation) shall meet Reliability Standard MOD-006-0_R1.
- M2.** The Transmission Service Provider’s procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**
Compliance Monitor: Regional Reliability Organizations
 - 1.2. **Compliance Monitoring Period and Reset Timeframe**
Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC compliance reporting process.
 - 1.3. **Data Retention**

Standard MOD-006-0.1 — Procedure for the Use of CBM Values

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Service Provider’s procedure for use of CBM is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Transmission Service Provider’s procedure for use of CBM addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 17, 2007	Corrected R1. — changed “preservation” to “reservation.”	Errata
0.1	October 29, 2008	<ul style="list-style-type: none">– Corrected Measure M1. — changed “preservation” to “reservation.”– BOT adopted errata changes; changed version number to “0.1”	Errata

A. Introduction

1. **Title:** Procedures for the Use of Capacity Benefit Margin Values
2. **Number:** MOD-006-0.1
3. **Purpose:** To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users,
4. **Applicability:**
 - 4.1. Transmission Service Provider.
5. **Effective Date:** ~~Immediately after approval of applicable regulatory authorities~~ April 1, 2005

B. Requirements

- R1. Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM preservation). The procedure shall include the following three components:
 - R1.1. Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.
 - R1.2. Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.
 - R1.3. Describe the conditions under which CBM may be available as Non-Firm Transmission Service.
- R2. Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..

C. Measures

- M1. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall meet Reliability Standard MOD-006-0_R1.
- M2. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**
Compliance Monitor: Regional Reliability Organizations
 - 1.2. **Compliance Monitoring Period and Reset Timeframe**
Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC compliance reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Service Provider’s procedure for use of CBM is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Transmission Service Provider’s procedure for use of CBM addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>0</u>	<u>September 17, 2007</u>	<u>Corrected R1. — changed “preservation” to “reservation.”</u>	<u>Errata</u>
<u>0.1</u>	<u>October 29, 2008</u>	<ul style="list-style-type: none"> – <u>Corrected Measure M1. — changed “preservation” to “reservation.”</u> – <u>BOT adopted errata changes: changed version number to “0.1”</u> 	<u>Errata</u>

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A. Introduction

- 1. Title:** Development of Dynamics System Models
- 2. Number:** MOD-015-0.1
- 3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
- 4. Applicability:**
 - 4.1.** Regional Reliability Organization
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steadystate system models, as appropriate, of Reliability Standard MOD-014-0_R1.
 - R1.1.** R1.1. The Regional Reliability Organization(s) shall develop Interconnection specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.
- R2.** The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

- M1.** The Regional Reliability Organization shall have Interconnection-specific dynamics system models in accordance with Reliability Standard MOD-015-0 Requirement 1 and MOD-015-0 Requirement 2.

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
 - 1.2. Compliance Monitoring Period and Reset Time Frame**

Development of dynamics system models: annually in accordance with each Interconnection's schedule.

Most recent dynamics system models: 30 calendar days.
 - 1.3. Data Retention**

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization’s cases was either not submitted by each Interconnection’s 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.

2.2. Level 2: Two of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

2.3. Level 3: Three of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

2.4. Level 4: Four or more of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Corrected typo in Section M1. — removed reference to Requirement R3.	January 26, 2007
0.1	October 29, 2008	BOT adopted errata changes; changed version number to “0.1”	Errata

A. Introduction

1. **Title:** Development of Dynamics System Models
2. **Number:** MOD-015-0.1
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. **Applicability:**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** [Immediately after approval of applicable regulatory authorities April 1, 2005](#)

B. Requirements

- R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steadystate system models, as appropriate, of Reliability Standard MOD-014-0_R1.
 - R1.1. R1.1. The Regional Reliability Organization(s) shall develop Interconnection specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.
- R2. The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

- M1. The Regional Reliability Organization shall have Interconnection-specific dynamics system models in accordance with Reliability Standard MOD-015-0 Requirement 1 and MOD-015-0 Requirement 2, ~~and MOD-015-0_R3~~

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

Development of dynamics system models: annually in accordance with each Interconnection's schedule.

Most recent dynamics system models: 30 calendar days.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization’s cases was either not submitted by each Interconnection’s 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.

2.2. Level 2: Two of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

2.3. Level 3: Three of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

2.4. Level 4: Four or more of a Regional Reliability Organization’s cases were either not submitted by each Interconnection’s 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).

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Corrected typo in Section M1. — removed reference to Requirement R3.	January 26, 2007
0.1	October 29, 2008	BOT adopted errata changes; changed version number to “0.1”	Errata

A. Introduction

1. **Title:** Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
2. **Number:** MOD-016-1.1
3. **Purpose:** Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed.
4. **Applicability:**
 - 4.1. Planning Authority.
 - 4.2. Regional Reliability Organization.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.
 - R1.1.** The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021.

The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.
- R2.** The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.
 - R2.1.** The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.
- R3.** The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.
 - R3.1.** The Planning Authority shall make this distribution within 30 calendar days of approval.

C. Measures

- M1.** The Planning Authority and Regional Reliability Organization's documentation for actual and forecast customer data shall contain all items identified in R1.
- M2.** The Regional Reliability Organization shall have evidence it provided its actual and forecast customer data reporting requirements as required in Requirement 2.
- M3.** The Planning Authority shall have evidence it provided its actual and forecast customer data and reporting requirements as required in Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor for Planning Authority: Regional Reliability Organization.

Compliance Monitor for Regional Reliability Organization: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

The Regional Reliability Organization and Planning Authority shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

- 2.1. Level 1:** Documentation does not address completeness and double counting of customer data.
- 2.2. Level 2:** Documentation did not address one of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data).
- 2.3. Level 3:** No evidence documentation was distributed as required.
- 2.4. Level 4:** Either the documentation did not address two of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 1, 2006	Corrected sequential numbering problem in Sections R2. and R3.	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata

A. Introduction

1. **Title:** Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
2. **Number:** MOD-016-1.1
3. **Purpose:** Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed.
4. **Applicability:**
 - 4.1. Planning Authority.
 - 4.2. Regional Reliability Organization.
5. **Effective Date:** ~~Six months after BOT approval.~~ Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.
 - R1.1.** The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021.

The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.
- R2.** The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.
 - R2.1.** The Regional Reliability Organization shall make this distribution within 30 calendar days of approval. ← - - - - Formatted: Bullets and Numbering
- R3.** The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area.
 - R3.1.** The Planning Authority shall make this distribution within 30 calendar days of approval. ← - - - - Formatted: Bullets and Numbering

C. Measures

- M1.** The Planning Authority and Regional Reliability Organization's documentation for actual and forecast customer data shall contain all items identified in R1.
- M2.** The Regional Reliability Organization shall have evidence it provided its actual and forecast customer data reporting requirements as required in Requirement 2.
- M3.** The Planning Authority shall have evidence it provided its actual and forecast customer data and reporting requirements as required in Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor for Planning Authority: Regional Reliability Organization.

Compliance Monitor for Regional Reliability Organization: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

The Regional Reliability Organization and Planning Authority shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation does not address completeness and double counting of customer data.

2.2. Level 2: Documentation did not address one of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data).

2.3. Level 3: No evidence documentation was distributed as required.

2.4. Level 4: Either the documentation did not address two of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 1, 2006	Corrected sequential numbering problem in Sections R2. and R3.	January 26, 2007 Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to "1.1"	Errata

Adopted by Board of Trustees: [May 2, 2006](#)[October 29, 2008](#)

Page 3 of 3

[Effective Date: Six months after BOT approval.](#)

A. Introduction

- 1. Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**
- 2. Number:** MOD-017-0.1
- 3. 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 continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
- 4. Applicability:**
 - 4.1.** Load-Serving Entity.
 - 4.2.** Planning Authority.
 - 4.3.** Resource Planner.
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1.
 - R1.1.** Integrated hourly demands in megawatts (MW) for the prior year.
 - R1.2.** Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
 - R1.3.** Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
 - R1.4.** 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.

C. Measures

- M1.** Load-Serving Entity, Planning Authority, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided load data per Standard MOD-017-0_R1.

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Standard MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually or as specified in the documentation (Standard MOD-016-1_R1.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

3. **Level 1:** Did not provide actual and forecast demands and Net Energy for Load data in one of the four areas as required in Reliability Standard MOD-017-0_R1.
4. **Level 2:** Did not provide actual and forecast demands and Net Energy for Load data in two of the four areas as required in Reliability Standard MOD-017-0_R1.
5. **Level 3:** Did not provide actual and forecast demands and Net Energy for Load data in three of the four areas as required in Reliability Standard MOD-017-0_R1.
6. **Level 4:** Did not provide actual and forecast demands and Net Energy for Load data in any of the areas as required in Reliability Standard MOD-017-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 18, 2008	Revised R1. And D1.2. to reflect update in version from “MOD-016-0_R1” to MOD-016-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata

A. Introduction

1. **Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**
2. **Number:** [MOD-017-0.1](#)
3. **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 continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
 - 4.1. Load-Serving Entity.
 - 4.2. Planning Authority.
 - 4.3. Resource Planner.
5. **Effective Date:** [Immediately after approval of applicable regulatory authorities April 1, 2005](#)

B. Requirements

- R1. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-10_R1.
 - R1.1. Integrated hourly demands in megawatts (MW) for the prior year.
 - R1.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
 - R1.3. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
 - R1.4. 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.

C. Measures

- M1. Load-Serving Entity, Planning Authority, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided load data per Standard MOD-017-0_R1.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Standard MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually or as specified in the documentation (Standard MOD-016-10_R1.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

3. **Level 1:** Did not provide actual and forecast demands and Net Energy for Load data in one of the four areas as required in Reliability Standard MOD-017-0_R1.
4. **Level 2:** Did not provide actual and forecast demands and Net Energy for Load data in two of the four areas as required in Reliability Standard MOD-017-0_R1.
5. **Level 3:** Did not provide actual and forecast demands and Net Energy for Load data in three of the four areas as required in Reliability Standard MOD-017-0_R1.
6. **Level 4:** Did not provide actual and forecast demands and Net Energy for Load data in any of the areas as required in Reliability Standard MOD-017-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 18, 2008	Revised R1. And D1.2. to reflect update in version from “MOD-016-0_R1” to MOD-016-1_R1.”	Errata
<u>0.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “0.1”</u>	<u>Errata</u>

A. Introduction

1. **Title:** **Reporting of Interruptible Demands and Direct Control Load Management**
2. **Number:** MOD-019-0.1
3. **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 assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
 - 4.1. Load-Serving Entity.
 - 4.2. Planning Authority.
 - 4.3. Transmission Planner.
 - 4.4. Resource Planner.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data 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 Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-1_R1.

C. Measures

- M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible demands and DCLM data per Reliability Standard MOD-019-0_R1.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Each Regional Reliability Organization.
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

Annually or as specified in the documentation (Reliability Standard MOD-016-1_R1.)
 - 1.3. **Data Retention**

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide forecasts of interruptible Demands and DCLM data as required in Standard MOD-019-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
	February 8, 2005	Approved by BOT	Revised
0	July 24, 2007	Changed reference R1. and Dl.1.2. to “MOD-016-0_R1” to MOD-016-1_R1.” (New version number.)	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”.	Errata

A. Introduction

1. **Title:** **Reporting of Interruptible Demands and Direct Control Load Management**
2. **Number:** MOD-019-0.1
3. **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 assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
 - 4.1. Load-Serving Entity.
 - 4.2. Planning Authority.
 - 4.3. Transmission Planner.
 - 4.4. Resource Planner.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities April 1, 2005

B. Requirements

- R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data 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 Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-10_R1.

C. Measures

- M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible demands and DCLM data per Reliability Standard MOD-019-0_R1.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Each Regional Reliability Organization.
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

Annually or as specified in the documentation (Reliability Standard MOD-016-10_R1.)
 - 1.3. **Data Retention**

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide forecasts of interruptible Demands and DCLM data as required in Standard MOD-019-0_R1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
	February 8, 2005	Approved by BOT	Revised
<u>0</u>	<u>July 24, 2007</u>	<u>Changed reference R1. and Dl.1.2. to “MOD-016-0_R1” to MOD-016-1_R1.” (New version number.)</u>	<u>Errata</u>
<u>0.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “0.1”.</u>	<u>Errata</u>

A. Introduction

- 1. Title: Special Protection System Misoperations**
- 2. Number:** PRC-016-0.1
- 3. Purpose:** To ensure that all Special Protection Systems (SPS) 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.
- 4. Applicability:**
 - 4.1.** Transmission Owner that owns an SPS.
 - 4.2.** Generator Owner that owns an SPS.
 - 4.3.** Distribution Provider that owns an SPS.
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it analyzed SPS operations and maintained a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it took corrective actions to avoid future misoperations.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

2.3. Level 3: Documentation of SPS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of SPS misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	July 3, 2007	Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata

A. Introduction

1. **Title: Special Protection System Misoperations**
2. **Number:** PRC-016-0.1
3. **Purpose:** To ensure that all Special Protection Systems (SPS) 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.
4. **Applicability:**
 - 4.1. Transmission Owner that owns an SPS.
 - 4.2. Generator Owner that owns an SPS.
 - 4.3. Distribution Provider that owns an SPS.
5. **Effective Date:** [Immediately after approval of applicable regulatory authorities April 1, 2005](#)

B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it analyzed SPS operations and maintained a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-0126-0_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

2.3. Level 3: Documentation of SPS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of SPS misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>0</u>	<u>July 3, 2007</u>	<u>Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.”</u>	<u>Errata</u>
<u>0.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “0.1”</u>	<u>Errata</u>

A. Introduction

- 1. Title:** **Operational Reliability Information**
- 2. Number:** TOP-005-1.1
- 3. Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
- 4. Applicability**
 - 4.1.** Transmission Operators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Reliability Coordinators.
 - 4.4.** Purchasing Selling Entities.
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.
 - R1.1.** Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.
- R2.** As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R3.** 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 these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R4.** Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

- M1.** Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R4 is providing the requesting entities 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).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R4 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity’s list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 6, 2007	Revised D.2.1 and D.2.4 reference “Requirements R1 to R5” “to Requirements R1 to R4.”	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata

**Attachment 1-TOP-005-1.1
Electric System Reliability Data**

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall 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.

Standard TOP-005-1.1 — Operational Reliability Information

- 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.

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-1.1
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
 - 4.4. Purchasing Selling Entities.
5. **Effective Date:** ~~November 1, 2006~~ Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.
 - R1.1. Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.
- R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R3. 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 these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

- M1. Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R45 is providing the requesting entities 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).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R45 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity’s list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<u>1</u>	<u>November 6, 2007</u>	<u>Revised D.2.1 and D.2.4 reference “Requirements R1 to R5” “to Requirements R1 to R4.”</u>	<u>Errata</u>
<u>1.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to “1.1”</u>	<u>Errata</u>

Attachment 1-TOP-005-01.1

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall 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.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, 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 conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
 - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
 - R1.3.5. Have all projected firm transfers modeled.

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	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	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^e : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^e , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^e : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^e : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^e :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled ^c	No
7. Transformer	Yes	Planned/ Controlled ^c	No	
8. Transmission Circuit	Yes	Planned/ Controlled ^c	No	
9. Bus Section	Yes	Planned/ Controlled ^c	No	

Standard TPL-001-0.1 — System Performance Under Normal Conditions

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating 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 Reliability 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 reliability 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) 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 reliability of the interconnected transmission systems.
- d) 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.
- e) 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, and not because of an intentional design delay.
- f) 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.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** Immediately after approval of applicable regulatory authorities April 1, 2005

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, 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 conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
 - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
 - R1.3.5. Have all projected firm transfers modeled.

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
<u>0</u>	<u>June 3, 2005</u>	<u>Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2</u>	<u>Errata</u>
<u>0</u>	<u>July 24, 2007</u>	<u>Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.</u>	<u>Errata</u>
<u>0.1</u>	<u>October 29, 2008</u>	<u>BOT adopted errata changes; updated version number to "0.1"</u>	<u>Errata</u>

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
		System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	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	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^e : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^e , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^e : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^e : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^e :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled ^c	No
7. Transformer	Yes	Planned/ Controlled ^c	No	
8. Transmission Circuit	Yes	Planned/ Controlled ^c	No	
9. Bus Section	Yes	Planned/ Controlled ^c	No	

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating 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 Reliability 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 reliability 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) 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 reliability of the interconnected transmission systems.
- d) 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.
- e) 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, and not because of an intentional design delay.
- f) 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.

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules

A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Schedules
2. **Number:** VAR-002-1.1a
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
 - 4.1. Generator Operator.
 - 4.2. Generator Owner.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
- R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings¹) as directed by the Transmission Operator.
 - R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.
 - R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:
 - R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
 - R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.
- R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.
 - R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
 - R4.1.1. Tap settings.
 - R4.1.2. Available fixed tap ranges.

¹ When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

- 2.1.1** One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.
- 2.1.2** One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

- 2.2.1** More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.
- 2.2.2** More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

- 2.3.1** More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.
- 2.3.2** More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

- 2.4.1** Failed to comply with the Transmission Operator’s directives as identified in R2.
- 2.4.2** Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.
- 2.4.3** Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

- 3.1.1 Level One:** Not applicable.
- 3.1.2 Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.
- 3.1.3 Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage
- 3.1.4 Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to “1.1a”	Errata

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (*automatic voltage regulator in service and controlling voltage*) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage *or Reactive Power output* as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rationale is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rationale stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

A. Introduction

- 1. Title:** Generator Operation for Maintaining Network Voltage Schedules
- 2. Number:** VAR-002-1.1a
- 3. Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
- 4. Applicability**
 - 4.1.** Generator Operator.
 - 4.2.** Generator Owner.
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

- R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
- R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings¹) as directed by the Transmission Operator.
 - R2.1.** When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.
 - R2.2.** When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- R3.** Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:
 - R3.1.** A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
 - R3.2.** A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.
- R4.** The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.
 - R4.1.** For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
 - R4.1.1.** Tap settings.
 - R4.1.2.** Available fixed tap ranges.

¹ When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

- 2.1.1** One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.
- 2.1.2** One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

- 2.2.1** More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.
- 2.2.2** More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

- 2.3.1** More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.
- 2.3.2** More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

- 2.4.1** Failed to comply with the Transmission Operator’s directives as identified in R2.
- 2.4.2** Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.
- 2.4.3** Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

- 3.1.1 Level One:** Not applicable.
- 3.1.2 Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.
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- 3.1.4 Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

Standard VAR-002-1.1a — Generator Operation for Maintaining Network Voltage Schedules

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

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Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
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Appendix 1

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Request:

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Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage *or Reactive Power output* as directed by the Transmission Operator.

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Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rationale stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

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Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Exhibit B

NERC Standards Committee Errata Procedure

Standards Committee Procedure

- Title:** **Approving Errata in an Approved Reliability Standard**
- Purpose:** To provide an approval process for incorporating errata changes in approved reliability standards
- Conditions:** When someone notifies the Standards Administrator that there is an error in an approved standard and the standards staff identifies the error as “errata”
- Errata:** For the purpose of this procedure, errata are errors in approved standards that, if corrected, do not change the scope or intent of the associated approved standard and do not have a material impact on the end users of the standard. Errata can include such things as:
- A misspelled word
 - An incorrect reference to a requirement or measure
 - An error, such as a missing word etc. that, when added or corrected, does not change the scope or technical content of the standard

Responsibility	Activity
Standards Administrator	Forward each notice of an error in an approved standard to the Standards Process Manager.
Standards Process Manager	<p>If the error falls into the errata category, produce a clean and red line version of the standard that shows the proposed correction(s).</p> <p>If the error is associated with an active project notify the drafting team of the error so that the error is not duplicated.</p> <p>If the error does not meet the errata criteria, and there are no active standards projects involving the applicable standard, add the error to the “Standards Issues Database” for inclusion in the next SAR submitted to revise the associated standard.</p>
Standards Committee	Review the proposed errata modification and determine if it qualifies as errata as defined above. The Standards Committee may seek the opinion of a technical committee. If approved as errata, direct staff to post the clean and red line versions of the standard for a 30-day comment period.
Standards Process Manager	<p>If the Standards Committee authorizes posting for stakeholder comment:</p> <ul style="list-style-type: none"> – Post the clean and redline versions of the standard for a 30-day comment period. – Identify the posting as an errata change and ask stakeholders if they agree that the proposed modification is immaterial and if they support the modification. – Provide timetable including when the board will act on the errata.
Stakeholders	Provide comments on proposed errata. If stakeholders do not support the revision as errata they should include reasons why they believe the change is material or does not qualify as errata.

Standards Committee's Process Subcommittee	Prepare responses to stakeholder comments and submit with a recommendation to the Standards Committee for review and action.
Standards Committee	Review Process Subcommittee recommendation and determine whether to make further modifications to the draft standard and post again if necessary, seek the opinion of a technical committee, or authorize moving the errata forward for board adoption and filing with regulatory authorities.
Director, Standards	Submit the revised standard and errata to the board for its approval.
Board of Trustees	The board shall adopt or reject the revised standard as errata, but may not modify the proposed reliability standard. If the board chooses not to adopt the revised standard, it shall provide its reasons for not doing so.
Standards Administrator	Modify the board approved version of the standard to include the approved correction, update the standard's version number and send a notice of the approval and associated modification to the standards list servers.
Director, Standards	Submit the revised standard and errata to applicable regulatory authorities for approval.
Standards Administrator	Once approval is received from applicable regulatory authorities, modify applicable regulatory approved version and send a notice to the standards list servers.

Exhibit C

Comments Received to the Errata Posting

Comments on Reliability Standards Errata

The Standards Committee thanks all commenters who submitted comments on the various Reliability Standards errata. NERC posted the errata for a 30-day comment period from July 2 through July 31, 2008 to provide stakeholders an opportunity to identify any material impacts associated with the errata that staff may have missed. The stakeholders were asked to provide feedback on the errata through a special Standard Comment Form. There were more than 14 sets of comments, including comments from 49 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/~filez/standards/Standards_Errata.html

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

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

Index to Questions, Comments, and Responses

1. There are several approved NERC standards that contain errors that have been identified as errata. If you disagree with this determination, please identify the specific standard that includes the errata, and the material impact of not accepting the error as errata. 5

Consideration of Comments on Various Reliability Standards Errata

The Industry Segments are:

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

Commenter		Organization		Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Guy Zito	NPCC RSC		x										
Additional Member	Additional Organization	Region		Segment Selection										
1.	David Kiguel	Hydro One Networks, Inc.		NPCC		1								
2.	Don Nelson	Massachusetts Dept. of Public Utilities		NPCC		9								
3.	Ron Falsetti	Independent Electricity System Operator		NPCC		2								
4.	Ralph Ruffano	New York Power Authority		NPCC		5								
5.	Mike Ranalli	National Grid		NPCC		3								
6.	Brian Gooder	Ontario Power Generation, Inc.		NPCC		5								
7.	Roger Champagne	Hydro-Quebec TransEnergie		NPCC		2								
8.	Alan Adamson	New York State Reliability Council		NPCC		10								
9.	Ron Hart	Dominion Resources, Inc.		NPCC		5								
10.	Rick White	Northeast Utilities		NPCC		1								
11.	Greg Campoli	New York Independent System Operator		NPCC		2								
12.	Kathleen Goodman	ISO New England		NPCC		2								
13.	Ed Thompson	Consolidated Edison Co. of New York, Inc.		NPCC		1								
14.	Sylvain Clermont	Hydro-Quebec TransEnergie		NPCC		1								
15.	Randy MacDonald	New Brunswick System Operator		NPCC		2								
16.	Brian Evans-Mongeon	Utility Services		NPCC		6								
17.	Mike Gildea	Constellation Energy		NPCC		6								
18.	Lee Pedowicz	NPCC		NPCC		10								
19.	Gerry Dunbar	NPCC		NPCC		10								
20.	Brian Hogue	NPCC		NPCC		10								
2.	Kris Manchur	Manitoba Hydro		x		x		x	x					
3.	Jim Eckels	FirstEnergy Corp.		x										
4.	Sam Ciccone	FirstEnergy Corp.		x		x		x	x					
Additional Member	Additional Organization	Region	Segment Selection											
1.	Doug Hohlbaugh	FE	RFC	1, 3, 5, 6										
2.	Dave Folk	FE	RFC	1, 3, 5, 6										
5.	Denise Koehn	Bonneville Power Administration		x		x		x	x					
6.	Alan Gale	City of Tallahassee		x		x		x						
7.	Kirit S. Shah	Ameren		x		x				x				

Consideration of Comments on Various Reliability Standards Errata

Commenter		Organization	Industry Segment										
			1	2	3	4	5	6	7	8	9	10	
8.	Ron Falsetti	Ontario IESO		x									
9.	Larry Brusseau	MRO NERC Standards Review Subcommittee (NSRS)											x
Additional Member	Additional Organization	Region	Segment Selection										
1.	Neal Balu	Wisconsin Public Service	MRO				3, 4, 5, 6						
2.	Terry Bilke	Midwest ISO Inc.	MRO				2						
3.	Carol Gerou	Minnesota Power	MRO				1, 3, 5, 6						
4.	Jim Haigh	Western Area Power Administration	MRO				1, 6						
5.	Ken Goldsmith	Alliant Energy	MRO				4						
6.	Tom Mielnik	MidAmerican Energy Company	MRO				1, 3, 5, 6						
7.	Pam Sordet	Xcel Energy	MRO				1, 3, 5, 6						
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO				1, 3, 5, 6						
9.	Eric Ruskamp	Lincoln Electric System	MRO				1, 3, 5, 6						
10.	Joseph Knight	Great River Energy	MRO				1, 3, 5, 6						
11.	Joe DePoorter	Madison Gas & Electric	MRO				3, 4, 5, 6						
12.	Mike Brytowski	Midwest Reliability Organization	MRO				10						
10.	Alice Druffel	Xcel Energy	x			x		x	x				
11.	Jason Shaver	American Transmission Company	x										
12.	Martin Bauer	U.S. Department of Reclamation						x					
13.	Jalal Babik	Dominion Resources, Inc.						x					
Additional Member	Additional Organization	Region	Segment Selection										
1.	Jalal Babik	Dominion Resources Inc.	SERC				5						
2.	Louis Slade	Dominion Resources Inc.	SERC				5						
14.	Marie Knox	Midwest ISO, Inc.		x									

Consideration of Comments on Various Reliability Standards Errata

1. There are several approved NERC standards that contain errors that have been identified as errata. If you disagree with this determination, please identify the specific standard that includes the errata, and the material impact of not accepting the error as errata.

Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.

No - I do not agree that the noted errors in the reliability standards are correctly identified as errata.

Summary Consideration:

Organization	Question 1:	Question 1 Comments:
NPCC RSC	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	Note that in EOP-002-2 Capacity and Energy Emergencies there is an error in the errata. In Version 1 of the Version History, there is an erroneous date of Sept. 19, 2008.
Response:		
Manitoba Hydro	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	EOP-002-2 - Although adding "Load Serving Entity" in the Applicability List is a stretch for an errata we believe it can be justified being that from day one the Attachment 1 clearly includes the Load Serving Entity. MOD-006-0 - Should also change "preservation" to "reservation" in M1 and M2
Response:		
FirstEnergy Corp.	No - I do not agree that the noted errors in the reliability standards are correctly identified as errata.	EOP-004: Attachment 2 needs a complete re-write to explain the new DOE oe-417 form. The only change I saw was to change EIA to OE. It currently doesn't show the 1 & 6 hour reporting requirements of the new DOE oe-417 report. I feel this might be more than an errata change.
Response:		
FirstEnergy Corp.	No - I do not agree that the noted errors in the reliability standards are correctly identified as errata.	<p>BAL-006-1: Version history wording should be revised from, "Added following to "Effective Date:" and footer This standard will expire for one year beyond the effective date..." This standard will expire one year beyond the effective date... The other proposed errata should be reviewed for this same condition and adjusted as needed.</p> <p>EOP-004-1: In EOP-004-1 one instance of EIA-417 was not changed to OE-417 on page 10 of 17 in the paragraph that begins, "Form EIA-417 must be submitted..."</p> <p>EOP-004-1 Att. 2 - The nine (9) items listed at the bottom of pg. 10 and top of pg. 11 should match the OE-417 document which lists the following twelve (12) items:</p> <ol style="list-style-type: none"> 1. Actual physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations 2. Actual cyber or communications attack that causes major interruptions of

Consideration of Comments on Various Reliability Standards Errata

		<p>electrical system operations</p> <ol style="list-style-type: none"> 3. Complete operational failure or shut-down of the transmission and/or distribution electrical system 4. Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system 5. Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident 6. Load shedding of 100 Megawatts or more implemented under emergency operational policy 7. System-wide voltage reductions of 3 percent or more 8. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system 9. Suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism which target components of any security systems 10. Suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability 11. Loss of electric service to more than 50,000 customers for 1 hour or more 12. Fuel supply emergencies that could impact electric power system adequacy or reliability <p>Also, the first sentence of the next paragraph following the list of system failures and interruptions (as shown above) should be revised as follows to reflect the 1hr and 6hr requirements of the DOE form:</p> <p>"The initial DOE Emergency Incident and Disturbance Report (form OE-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption if any of the Items 1-8 are checked, but may be extended to within 6 hours if ONLY one or more of the Items in 9-12 are checked."</p> <p>Implementation Plan for FAC-010-1, FAC-011-1 and FAC-014-1: On Pg.4 of the implementation plan, the effective date is showing timelines after BOT approval. But technically, the effective date is a timeframe after regulatory approval, or in those jurisdictions not requiring regulatory approval, then a timeframe after BOT approval.</p> <p>IRO-001-1: Why does A.5. state: "(Proposed) Effective Date" - Shouldn't it say "Effective Date"?</p> <p>General to all Standards: We believe the effective dates shown in each standard reflect regulatory approval.</p>
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Consideration of Comments on Various Reliability Standards Errata

		For instance, all of the initial 83 standards were approved by FERC per order 693 and effective March 2007. It should be clear in the standards what the actual regulatory "approval" dates are versus the actual "effective" dates which may be a timeframe after approval due to implementation periods.
Response:		
Bonneville Power Administration	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	
Response:		
City of Tallahassee	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	
Response:		
Ameren	No - I do not agree that the noted errors in the reliability standards are correctly identified as errata.	Concerning the 'Description of Correction' related to EOP-004-1, Disturbance Reporting: the statement incorrectly refers to Form OE-411. It should be Form OE-417 instead. As a result the Version History in the referenced Standard is correspondingly incorrect.
Response:		
Ontario IESO	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	The IESO supports these errata changes.
Response:		
MRO NERC Standards Review Subcommittee (NSRS)	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	Also note the following discrepancies: EOP-002-2, under Version History, version 1, the date may be wrong, "September 19, 2008" (?), this may be a type-o, possibly should read "2006". EOP-004-1, under Version History, version 1, under Action, the form (OE-411) that is referenced is not contained in the Standard; Possible a type-o, possibly should read "Form OE 417".
Response:		
Xcel Energy	No - I do not agree that the noted errors in the reliability standards are correctly identified as errata.	EOP-002-2 There appears to be no indication that Load Serving Entities (LSE) was "inadvertently omitted" from the applicability section of the standard. This type of "error" is substantial and should be vetted through the standards development process. Furthermore, an updated version, including LSEs, should not be posted until this has received proper approval. Recommend removing the updated version from the website immediately. In addition to the identified errata, we would like to point out these 2 additional errata: EOP-002-2 Version history date of Sept. 19, 2008 should be Sept. 19, 2006. MOD-006-0 The word "preservation" should be corrected to "reservation" in the Measures, in addition to the Requirements.
Response:		
American Transmission Company		All of the standards list in this errata proceeding should have its version number updated in order to indicate that a change occurred. BAL-001-0a changes to BAL-001-1a BAL-003-0a changes to BAL-003-1a BAL-005-0a changes to BAL-005-

Consideration of Comments on Various Reliability Standards Errata

		1aBAL-006-1 changes to BAL-006-2COM-001-1 changes to COM-001-2EOP-002-2 changes to EOP-002-3.....etc
Response:		
U.S. Department of Reclamation	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	In reference to TPL-001-0. The errata corrected the reference in M1 to read TPL-001-0 R1 and TPL-001-0 R2. The reference to R2 however is incorrect. R2 requires that Planning Authority and Transmission Planner shall provide a written summary and not a valid assessment and corrective plans as referenced in M1.
Response:		
Dominion Resources, Inc.	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	
Response:		
Midwest ISO, Inc.	Yes - I do agree that the noted errors in the reliability standards are correctly identified as errata.	
Response:		