Reliability Standards for the Bulk Electric Systems of North America
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:**

5. **Effective Date:** May 13, 2009

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 \( \varepsilon_1^2 \) 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.

\[
\text{AVG}_{\text{Period}} \left[ \frac{ACE_i}{10B_i} \right] \cdot \Delta F_i \leq \varepsilon_1^2 \text{ or } \frac{AVG_{\text{Period}} \left[ \frac{ACE_i}{10B_i} \right]}{\varepsilon_i^2} \leq 1
\]

The equation for ACE is:

\[
ACE = (N_{IA} - N_{IS}) - 10B (F_A - F_S) - I_{ME}
\]

where:

- \( N_{IA} \) is the algebraic sum of actual flows on all tie lines.
- \( N_{IS} \) 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 (\( N_{IA} \)) 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:

\[ L_{10} = 1.65 \sqrt{(-10B)} \sqrt{(-10B)} \]

\( \varepsilon_{10} \) 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, \( \varepsilon_{10} \), 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:

\[ CPS1 = (2 - CF) \times 100\% \]

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:

\[ CF = \frac{CF_{12\text{-month}}}{(\varepsilon^2_1)} \]

where: \( \varepsilon_1 \) 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.

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

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

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

\[ CF_{\text{clock-minute}} = \left[ \frac{ACE}{-10B} \right] \times \Delta F_{\text{clock-minute}} \]

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).

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

The 12-month compliance factor becomes:

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

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:

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

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

\[
\begin{align*}
&= 0 \text{ if } \\
&\left| \frac{\sum ACE}{n \text{ samples in 10-minutes}} \right| \leq L_{10} \\
&= 1 \text{ if } \\
&\left| \frac{\sum ACE}{n \text{ samples in 10-minutes}} \right| > L_{10}
\end{align*}
\]

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 (ACEi), 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%.

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**


**F. Associated Documents**

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

**Version History**

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<td>BOT Approval</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Implementation Date</td>
<td>New</td>
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<td>0</td>
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<td>July 24, 2007</td>
<td>Corrected R3 to reference M1 and M2 instead of R1 and R2.</td>
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<td>Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007</td>
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<td>In Section A.2., Added “a” to end of standard number.</td>
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<td>0.1a</td>
<td>May 13, 2009</td>
<td>Approved by FERC</td>
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### Appendix 1-BAL-001-0
CPS1 and CPS2 Data

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<tr>
<th>CPS1 DATA</th>
<th>Description</th>
<th>Retention Requirements</th>
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<tr>
<td>$\varepsilon_1$</td>
<td>A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.</td>
<td>Retain the value of $\varepsilon_1$ used in CPS1 calculation.</td>
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<tr>
<td>ACE$_i$</td>
<td>The clock-minute average of ACE.</td>
<td>Retain the 1-minute average values of ACE (525,600 values).</td>
</tr>
<tr>
<td>$B_i$</td>
<td>The Frequency Bias of the Balancing Authority Area.</td>
<td>Retain the value(s) of $B_i$ used in the CPS1 calculation.</td>
</tr>
<tr>
<td>$F_A$</td>
<td>The actual measured frequency.</td>
<td>Retain the 1-minute average frequency values (525,600 values).</td>
</tr>
<tr>
<td>$F_S$</td>
<td>Scheduled frequency for the Interconnection.</td>
<td>Retain the 1-minute average frequency values (525,600 values).</td>
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<table>
<thead>
<tr>
<th>CPS2 DATA</th>
<th>Description</th>
<th>Retention Requirements</th>
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<tr>
<td>V</td>
<td>Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than $L_{10}$.</td>
<td>Retain the values of V used in CPS2 calculation.</td>
</tr>
<tr>
<td>$\varepsilon_{10}$</td>
<td>A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.</td>
<td>Retain the value of $\varepsilon_{10}$ used in CPS2 calculation.</td>
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<tr>
<td>$B_i$</td>
<td>The Frequency Bias of the Balancing Authority Area.</td>
<td>Retain the value of $B_i$ used in the CPS2 calculation.</td>
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<tr>
<td>$B_S$</td>
<td>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.</td>
<td>Retain the value of $B_S$ used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).</td>
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<tr>
<td>U</td>
<td>Number of unavailable ten-minute periods per hour used in calculating CPS2.</td>
<td>Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.</td>
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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).

- 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.
Introduction

1. **Title:** Disturbance Control Performance
2. **Number:** BAL-002-0
3. **Purpose:**
   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**
   4.1. Balancing Authorities
   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   4.3. Regional Reliability Organizations

5. **Effective Date:** April 1, 2005

B. **Requirements**

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.
R2.2. Its allocation among members.
R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.
R2.4. The procedure for applying Contingency Reserve in practice.
R2.5. The limitations, if any, upon the amount of interruptible load that may be included.
R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently...
than annually, their probable contingencies to determine their prospective most severe single contingencies.

**R4.** A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

**R4.1.** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

**R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

**R5.** Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

**R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

**R5.2.** The Reserve Sharing Group reviews each member’s ACE in response to the activation of reserves. To be in compliance, a member’s ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

**R6.** A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

**R6.1.** The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

**R6.2.** The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

**C. Measures**

**M1.** A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority’s or of the Reserve Sharing Group’s most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery ($R_i$).
For loss of generation:

If $ACE_A < 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} \times 100\%$$

If $ACE_A \geq 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} \times 100\%$$

where:

- $MW_{LOSS}$ is the MW size of the Disturbance as measured at the beginning of the loss,
- $ACE_A$ is the pre-disturbance ACE,
- $ACE_M$ is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15 \text{ min}}$, and

The Balancing Authority or Reserve Sharing Group shall record the $MW_{LOSS}$ value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for $ACE_A$ on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of $ACE_A = -25 \text{ MW}$. 
The average percent recovery is the arithmetic average of all the calculated $R_i$’s for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

EachBalancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.
Multiple Contingencies within the Contingency Reserve Restoration Period –
Additional Reportable Disturbances that occur after the end of the Disturbance
Recovery Period but before the end of the Contingency Reserve Restoration Period
shall be reported and included in the compliance evaluation. However, the Balancing
Authority or Reserve Sharing Group can request a waiver from the Resources
Subcommittee for the event if the contingency reserves were rendered inadequate by
prior contingencies and a good faith effort to replace contingency reserve can be
shown.

2. **Levels of Non-Compliance**

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given
calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter
(offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for
the first calendar quarter of the year, the penalty is applied for May, June, and July.] The
increase shall be directly proportional to the non-compliance with the DCS in the preceding
quarter. This adjustment is not compounded across quarters, and is an additional percentage
of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may
choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing
Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-
compliant in the calendar quarter most recently completed shall provide written
documentation verifying that the Balancing Authority or Reserve Sharing Group will apply
the appropriate DCS performance adjustment beginning the first day of the succeeding month,
and will continue to apply it for three months. The written documentation shall accompany
the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve
Sharing Group is non-compliant.

2.1. **Level 1:** Value of the average percent recovery for the quarter is less than 100%
but greater than or equal to 95%.

2.2. **Level 2:** Value of the average percent recovery for the quarter is less than 95%
but greater than or equal to 90%.

2.3. **Level 3:** Value of average percent recovery for the quarter is less than 90% but
greater than or equal to 85%.

2.4. **Level 4:** Value of average percent recovery for the quarter is less than 85%.

E. **Regional Differences**

None identified.
## Version History

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WECC Standard BAL-002-WECC-1 - Contingency Reserves

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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<td>1. Post Draft Standard for initial industry comments</td>
<td>September 14, 2007</td>
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<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 20, 2007</td>
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<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 25, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
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Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for BAL-STD-002-0. BAL-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when BAL-STD-002-0 was approved as a NERC reliability standard. The drafting team implemented in the standard additional refinements to address concerns as explained in the document titled, “WECC Standard BAL-002-WECC-1 Contingency Reserves.” To assist in understanding the refinements made to the standard, the drafting team has developed a document that compares BAL-002-WECC-1, the permanent replacement standard, with the existing BAL-STD-002-0 (see BAL-002-WECC-1 Comparison).

This posting of the BAL-002-WECC-1 standard is for WECC Board of Director ballot. The Operating Committee recommends that the WECC Board of Directors approve the BAL-002-WECC-1 Standard as a permanent replacement standard for BAL-STD-002-0 and that the Board of Directors submit the standard to the NERC and FERC for approval.

Future Development Plan:

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<td>April 16-18, 2008</td>
</tr>
<tr>
<td>3. Drafting Team to review and respond to industry comments</td>
<td>May 2008</td>
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<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
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<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
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This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.
A. Introduction

1. Title: Contingency Reserves
2. Number: BAL-002-WECC-1
3. Purpose: Contingency Reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

4. Applicability

4.1 Balancing Authority
4.2 Reserve Sharing Group

5. Effective Date: On the first day of the next quarter, after receipt of applicable regulatory approval.

B. Requirements

R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum Contingency Reserve that is the sum of the following: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1. The greater of the following:

R1.1.1. An amount of reserve equal to the loss of the most severe single contingency; or

R1.1.2. An amount of reserve equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service).

R1.2. If the Source Balancing Authority designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink Balancing Authority shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s). This type of transaction cannot be designated as Spinning Reserves by the source BA. If the Source Balancing Authority does not designate the Interchange Transaction as part of its Contingency Reserve, the Sink Balancing Authority is not required to carry any additional Contingency Reserves under this Requirement.

R1.3. If the Sink Balancing Authority is designating an Interchange Transaction(s) as part of its Contingency Reserve either Spinning...
or Non-Spinning, the Source Balancing Authority shall increase its Contingency Reserves equal in amount and type, to the capacity transaction(s) where the Sink Balancing Authority is designating the transaction(s) as a resource to meet its Contingency Reserve requirements. These types of transactions could be designated as either spinning or non-spinning reserves. If designated as Spinning Reserves, all of the requirements of section R2.1 & R2.2 must be met.

**R2.** Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R2.2. Capable of fully responding within ten minutes.

**R3.** Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve which must be fully deployable within 10 minutes of notification to meet R1: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R3.1. Spinning Reserve

R3.2. Interruptible Load;

R3.3. Interchange Transactions designated by the source Balancing Authority as non-spinning contingency reserve;

R3.4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service;

R3.5. An amount of off-line generation which can be synchronized and generating; or

R3.6. Load, other than Interruptible Load, once the Reliability Coordinator has declared a capacity or energy emergency.

**C. Measures**

**M1.** The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it maintained 100% of required Contingency Reserve levels based upon data integrated over each clock hour except within the first 105 minutes (15 minute Disturbance Recovery Period, plus
90 minute Contingency Reserve Restoration Period) following an event requiring the activation of Contingency Reserves. For each hour Reserve Sharing Group or Balancing Authority shall have and provide upon request their Contingency Reserve Requirement in MW, how the requirement was calculated, and amount of Contingency Reserve available in MW. E-tags and/or contracts shall be provided to document any transactions under R1.2 and R1.3.

M2. The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it maintained at least 100% of minimum Spinning Contingency Reserve required based upon data averaged over each clock hour except within the first 105 minutes following an event requiring the activation of Contingency Reserves. For each hour, Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall have and provide upon request the Spinning Reserve Requirement in MW and amount of Spinning Reserve available in MW that is automatically responsive to frequency and can be fully deployed in 10 minutes.

M3. The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it used the acceptable types of reserve for each hour to meet R3.

M3.1 Any Reserve Sharing Group or Balancing Authority utilizing Load other than Interruptible Load shall submit documentation demonstrating that the Reliability Coordinator declared a Capacity and/or Energy Emergency prior to utilizing Load for Contingency Reserves.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports conducted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

Reserve Sharing Groups and Balancing Authorities shall submit to their Compliance Enforcement Authority a Contingency Reserve verification report on or before the tenth business day following the end of each calendar quarter.
1.2.1 Compliance Monitoring Period: One Clock Hour.

1.2.2 The Performance-reset Period is calendar quarter.

1.3 Data Retention

Reserve Sharing Groups and Balancing Authorities shall keep evidence for Measure M.1 through M3 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 1.4.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Section 1.4.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 1.4.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 1.4.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).
1.4.4. If an agent properly designated in accordance with Section 1.4.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 1.4.2 shall be subject to this Standard on an individual basis.

2. Violation Severity Levels for Requirement R1

2.1. **Lower:** There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve.

2.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve.

2.3. **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve.

2.4. **Severe:** There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 70% of the required Contingency Reserve.

3. Violation Severity Level for Requirement R2

3.1. **Lower:** There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 100% but greater than or equal to 90% of the required Spinning Reserve.

3.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 90% but greater than or equal to 80% of the required Spinning Reserve.

3.3. **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 80% but greater than or equal to 70% of the required Spinning Reserve.
3.4. **Severe:** There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 70% of the required Spinning Reserve.

4. **Violation Severity Level for Requirement R3**
   
   4.1 **Lower:** Not Applicable
   
   4.2 **Moderate:** Not Applicable
   
   4.3 **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority or Reserve Sharing Group used unacceptable resources for Contingency Reserves.
   
   4.4 **Severe:** Not Applicable

**Version History** – Shows Approval History and Summary of Changes in the Action Field

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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:
5. Effective Date: May 13, 2009

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.

Jointly Owned Unit

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).

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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.

- 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:

\[
ACE = (N_{IA} - N_{IS}) - 10B (F_A - F_S) - I_{ME}
\]
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 — 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.

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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.

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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-003-0b
3. Purpose:
   This standard provides a consistent method for calculating the Frequency Bias component of ACE.
4. Applicability:
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:

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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).
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Interpretation:
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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.

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A. Introduction
1. **Title:** Time Error Correction
2. **Number:** BAL-004-0
3. **Purpose:**
   The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.
4. **Applicability:**
   4.1. Reliability Coordinators
   4.2. Balancing Authorities
5. **Effective Date:** April 1, 2005

B. Requirements

   **R1.** Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.

   **R2.** The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.

   **R3.** Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:
   - **R3.1.** The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or
   - **R3.2.** The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

   **R4.** Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.
   - **R4.1.** Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures
Not specified.

D. Compliance
Not specified.

E. Regional Differences
None identified.
## Version History

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<td>August 8, 2005</td>
<td>Removed &quot;Proposed&quot; from Effective Date</td>
<td>Errata</td>
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</tbody>
</table>
A. Introduction

1. **Title:** Time Error Correction

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

3. **Purpose:**
   
   The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. **Applicability:**
   
   4.1. Reliability Coordinators
   
   4.2. Balancing Authorities

5. **Effective Date:** First day of first quarter after applicable regulatory approval or, in those jurisdictions where regulatory approval is not required, upon Board of Trustees approval.

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor.

R2. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

   R2.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

   R2.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e., 20% of the Frequency Bias Setting).

R3. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

   R3.1. Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.
Standard BAL-004-1 — Time Error Correction

Version History

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<td>1</td>
<td>March 26, 2008</td>
<td>Approved by Board of Trustees</td>
<td>Revised</td>
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Effective Date: First day of first quarter after applicable regulatory approval or, in those jurisdictions where regulatory approval is not required, upon Board of Trustees approval.
A. Introduction

Title: Automatic Time Error Correction

Number: BAL-004-WECC-01

Purpose: To maintain Interconnection frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal), and to ensure that Time Error Corrections are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.

Applicability:
1. Balancing Authorities (BA) that operate synchronously to the Western Interconnection.

Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Each BA that operates synchronously to the Western Interconnection shall continuously operate utilizing Automatic Time Error Correction (ATEC) in its Automatic Generation Control (AGC) system. [Risk Factor: Lower]

\[
ACE_{ATEC} = (NI_A - NI'_S) - 10B_i(F_s - F'_s) - T_{0b} + I_{ME}
\]

Where:

- \(NI_A\) = Net Interchange Actual (MW).
- \(F_A\) = Frequency Actual (Hz).
- \(F_S\) = Frequency Scheduled (Normally 60 Hz).
- \(B_i\) = Frequency Bias for the Balancing Authority’s Area (MW / 0.1 Hz).
- \(T_{0b}\) = Remaining Bilateral Payback for Inadvertent Interchange created prior to implementing automatic payback (MW).
- \(I_{ME}\) = Meter Error Correction (MW).
- \(NI'_S = NI_S - \frac{\Pi_{primary}^{on/off\ peak}}{(1 - Y) \times H}\)
- \(NI_S\) = Net Interchange Scheduled (MW).
- \(Y = B_i / B_S\).
- \(H\) = Number of Hours used to payback Inadvertent Interchange Energy. The WECC Performance Work Group has set the value of \(H\) to 3.
- \(B_S\) = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- \(\Pi_{primary}^{on/off\ peak}\) = is the Balancing Authority’s accumulated primary inadvertent interchange in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

\[
\Pi_{primary}^{on/off\ peak} = \text{last period’s } \Pi_{primary}^{on/off\ peak} + (1-Y) \times (I_{actual} - B_i \times \Delta TE/6)
\]

\(I_{actual}\) is the hourly Inadvertent Interchange for the last hour.

\(\Delta TE\) is the hourly change in system Time Error as distributed by the Interconnection Time Monitor.
Where:

\[ \Delta \text{TE} = \text{TE}_{\text{end hour}} - \text{TE}_{\text{begin hour}} - \text{TD}_{\text{adj}} - (t) \times (\text{TE offset}) \]

\( \text{TD}_{\text{adj}} \) is any operator adjustment to the control center Time Error to correct for differences with the time monitor.

\( t \) is the number of minutes of Manual Time Error Correction that occurred during the hour.

\( \text{TE offset} \) is 0.000 or +0.020 or -0.020.

R1.1. The absolute value of the WECC Automatic Time Error Correction term is limited as follows:

\[ \left| \Pi_{\text{primary}}^{\text{on/off peak}} \right| \left(1 - Y\right) \cdot H \leq L_{\text{max}} \]

Where \( L_{\text{max}} \) is chosen by the Balancing Authority and is bounded as follows:

\[ 0.20 \times |Bi| \leq L_{\text{max}} \leq L_{10} \]

\( L_{10} \) is the Balancing Authority CPS2 limit in MW. If the WECC Automatic Time Error Correction term is less than the upper limit, use the calculated WECC Automatic Time Error Correction term.

R1.2. Large accumulations of primary inadvertent point to an invalid implementation of ATEC, loose control, metering or accounting errors. A BA in such a situation should identify the source of the error(s) and make the corrections, recalculate the primary inadvertent from the time of the error, adjust the accumulated primary inadvertent caused by the error(s), validate the implementation of ATEC, set \( L_{\text{max}} \) equal to \( L_{10} \) and continue to operate with ATEC reducing the accumulation as system parameters allow.

R2. Each BA that is synchronously connected to the Western Interconnection and operates in any AGC operating mode other than ATEC shall notify all other BAs of its operating mode through the designated Interconnection communication system. Each BA while synchronously connected to the Western Interconnection will be allowed to have ATEC out of service for a maximum of 24 hours per calendar quarter, for reasons including maintenance and testing. [Risk Factor: Lower]

R3. BAs in the Western Interconnection shall be able to change their AGC operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; Tie Line Bias plus Time Error control (used in ATEC mode). The ACE used for NERC reports shall be the same ACE as the AGC operating mode in use. [Risk Factor: Lower]

R4. Regardless of the AGC operating mode each BA in the Western Interconnection shall compute its hourly Primary Inadvertent Interchange when hourly checkout is complete. If hourly checkout is not complete by 50 minutes after the hour, compute Primary Inadvertent Interchange with best available data. This hourly value shall be added to the appropriate accumulated Primary Inadvertent Interchange balance for either On-Peak or Off-Peak periods. [Risk Factor: Lower]

R4.1. Each BA in the Western Interconnection shall use the change in Time Error distributed by the Interconnection Time Monitor.

R4.2. All corrections to any previous hour Primary Inadvertent Interchange shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertent Interchange.
**R4.3.** Month end Inadvertent Adjustments are 100% Primary Inadvertent Interchange and shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertent Interchange, unless such adjustments can be pinpointed to specific hours in which case R4.2 applies.

**R4.4.** Each BA in the Western Interconnection shall synchronize its Time Error to the nearest 0.001 seconds of the system Time Error by comparing its reading at the designated time each day to the reading broadcast by the Interconnection Time Monitor. Any difference shall be applied as an adjustment to its current Time Error.

**C. Measures**

**M1.** For Requirement R1, a BA shall provide upon request a document showing that it is correctly calculating its hourly Primary Inadvertent Interchange number that is used to calculate its accumulated Primary Inadvertent Interchange and how it is used in its ACE equation for Automatic Time Error Correction.

**M2.** For Requirement R2, a BA shall record the date, time, reason, and notification [to other BAs within the Western Interconnection] for any time it is not operating utilizing Automatic Time Error Correction (ATEC) in its AGC system.

**M3.** For Requirement R3, a BA in the Western Interconnection must be able to demonstrate its ability to change its AGC operating mode when requested or during compliance audits and readiness reviews.

**M4.** For Requirement R4, a BA in the Western Interconnection must record its hourly Primary Inadvertent Interchange and keep an accurate record of its accumulation of Primary Inadvertent Interchange for both On-Peak and Off-Peak accounts. These records must be available for review when requested or during compliance audits and readiness reviews.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Entity

**Compliance Monitoring Period and Reset time Frame**

The reporting period for ATEC is one calendar quarter, starting on the first second of the quarter and ending on the final second of the quarter.

The Performance-reset Period is one calendar quarter.

**1.2. Data Retention**

Each Balancing Authority in the Western Interconnection shall retain its hourly calculation of total and Primary Inadvertent Interchange calculated hourly, as well as the amount of Primary Inadvertent paid back hourly for the preceding calendar year (January – December) plus the current year.

Each Balancing Authority in the Western Interconnection shall retain its total accumulated Inadvertent and total Primary Inadvertent, updated hourly, for On- and Off-Peak for the preceding calendar year (January – December) plus the current year.
Each Balancing Authority in the Western Interconnection shall retain its record of the amount of
time it operated without ATEC and the notification to the Interconnection of these times for the
preceding calendar year (January – December) plus the current year.

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

1.3. Additional Compliance Information

The Compliance Monitor shall use quarterly data to monitor compliance. The Compliance
Monitor may also use periodic audits (on site, per a schedule), with spot reviews and
investigations initiated in response to a complaint to assess performance.

The Balancing Authority in the Western Interconnection shall have the following documentation
available for its Compliance Monitor to inspect during a scheduled, on-site review or within five
business days of a request as part of a triggered investigation:

1.3.1. Source data for calculating Primary Inadvertent.

1.3.2. Data showing On- and Off-Peak Primary Inadvertent accumulations.

1.3.3. Data showing hourly payback of Primary Inadvertent.

1.3.4. Documentation on number of times not on ATEC and reasons for going off ATEC.

2. Violation Severity Levels

2.1. Lower: Time not in ATEC Mode greater than one day and less than or equal to three days, or if
a Balancing Authority in the Western Interconnection operates without ATEC and does not
notify other Balancing Authorities in the Western Interconnection 2 times in quarter.

2.2. Moderate: Time not in ATEC Mode greater than three days and less than or equal to five days,
or if a Balancing Authority in the Western Interconnection operates without ATEC and does not
notify other Balancing Authorities in the Western Interconnection 3 times in quarter.

2.3. High: Time not in ATEC Mode greater than five days and less than or equal to seven days, or if
a Balancing Authority in the Western Interconnection operates without ATEC and does not
notify other Balancing Authorities in the Western Interconnection 4 times in quarter.

2.4. Severe: Time not in ATEC Mode greater than seven days, or if a Balancing Authority in the
Western Interconnection operates without ATEC and does not notify other Balancing Authorities
in the Western Interconnection more than 4 times in quarter or Balancing Authority in the
Western Interconnection cannot change AGC operating mode or Balancing Authority in the
Western Interconnection incorrectly calculates Primary Inadvertent.
## Version History

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<td>1</td>
<td>October 17, 2006</td>
<td>Created Standard from Procedure.</td>
<td>Errata</td>
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<td>1</td>
<td>February 6, 2007</td>
<td>Changed the Standard Version from 0 to 1 in the Version History Table.</td>
<td>Errata</td>
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<td>1</td>
<td>February 6, 2007</td>
<td>The upper limit bounds to the amount of Automatic Time Error Correction term was inadvertently omitted during the Standard Translation. The bound was added to the requirement R1.4.</td>
<td>Errata</td>
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<td>1</td>
<td>February 6, 2007</td>
<td>The statement “The Time Monitor may declare offsets in 0.001-second increments” was moved from TOffset to TDadj and offsets was corrected to adjustments.</td>
<td>Errata</td>
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<td>1</td>
<td>February 6, 2007</td>
<td>The reference to seconds was deleted from the TE offset term.</td>
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<td>1</td>
<td>June 19, 2007</td>
<td>The standard number BAL-STD-004-1 was changed to BAL-004-WECC-01 to be consistent with the NERC Regional Reliability Standard Numbering Convention.</td>
<td>Errata</td>
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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: May 13, 2009

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 (IME) 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:

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<th>Device</th>
<th>Accuracy</th>
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<tr>
<td>Digital frequency transducer</td>
<td>$\leq 0.001$ Hz</td>
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<tr>
<td>MW, MVAR, and voltage transducer</td>
<td>$\leq 0.25$ % of full scale</td>
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<tr>
<td>Remote terminal unit</td>
<td>$\leq 0.25$ % of full scale</td>
</tr>
<tr>
<td>Potential transformer</td>
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<td>Current transformer</td>
<td>$\leq 0.50$ % of full scale</td>
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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).

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**Version History**

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<td>Errata</td>
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<tr>
<td>0a</td>
<td>December 19, 2007</td>
<td>Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007</td>
<td>Addition</td>
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<td>0a</td>
<td>January 16, 2008</td>
<td>Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.</td>
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<td>February 12, 2008</td>
<td>Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.</td>
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<td>0.1b</td>
<td>October 29, 2008</td>
<td>BOT approved errata changes; updated version number to “0.1b”</td>
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<td>0.1b</td>
<td>May 13, 2009</td>
<td>FERC approved – Updated Effective Date and Footer</td>
<td>Addition</td>
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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

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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

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:

5. Effective Date: May 1, 2006

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.

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<td>April 1, 2005</td>
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<td>Correction</td>
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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:

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

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<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to 1.1</td>
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A. Introduction

1. Title: Planning Resource Adequacy Analysis, Assessment and Documentation
2. Number: BAL-502-RFC-02
3. Purpose:
   To establish common criteria, based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RFC) region

4. Applicability
   4.1 Planning Coordinator

5. Effective Date:
   5.1 Upon RFC Board approval

B. Requirements

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [Violation Risk Factor: Medium]:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year1 analyzed (per R1.2) being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median2 forecast peak Net Internal Demand (planning reserve margin).

R1.2 Be performed or verified separately for each of the following planning years:

---

1 The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).
2 The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).
R1.2.1 Perform an analysis for Year One.

R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.3 Include the following subject matter and documentation of its use:

R1.3.1 Load forecast characteristics:
- Median (50:50) forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/Interruptible Demand.

R1.3.2 Resource characteristics:
- Historic resource performance and any projected changes
- Seasonal resource ratings
- Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
- Criteria for including planned resource additions in the analysis

R1.3.3 Transmission limitations that prevent the delivery of generation reserves

R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis
**R1.3.4** Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

**R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

**R1.5** Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.

**R1.6** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

**R1.7** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.

**R2** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis [Violation Risk Factor: Lower].

**R2.1** This documentation shall cover each of the years in Year One through ten.

**R2.2** This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

**R2.3** The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.
C. Measures

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor - Reliability First Corporation

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year

1.3. Data Retention

The Planning Coordinator shall retain information from the most current and prior two years.

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

2. Violation Severity Levels

<table>
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<tr>
<th>Req. Number</th>
<th>LOWER</th>
<th>MODERATE</th>
<th>HIGH</th>
<th>SEVERE</th>
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<tr>
<td>R1</td>
<td>The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they</td>
<td>The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from R1.1 as a percentage of the net Median forecast peak Load per R1.1.2</td>
<td>The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R1.2</td>
<td>The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1.</td>
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OR

OR

The Planning Coordinator Resource

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<th>were not included</th>
<th>The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of its use</th>
<th>The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per R1.2.2</th>
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<td>OR</td>
<td>The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under R1.3.2 and documentation of its use</td>
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<td>Or</td>
<td>The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of their use</td>
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<td>OR</td>
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<td>Or</td>
<td>The Planning Coordinator failed to perform an analysis for Year One per R1.2.1</td>
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<td>Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per R1.1</td>
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<tr>
<td><strong>R2</strong></td>
<td>The Planning Coordinator failed to publicly post the documents as specified</td>
<td>The Planning Coordinator failed to document the projected Load and resource</td>
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The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per R1.3.4

OR

The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included

OR

The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per R1.6
per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3

capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per R2.1.

capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per R2.1.

capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per R2.

OR

The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per R2.2.

OR

The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per R2.1.

**Definitions:**

**Resource Adequacy** - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

**Net Internal Demand** - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

**Peak Period** - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

**Year One** - The planning year that begins with the upcoming annual Peak Period.

The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:
**Direct Control Load Management** – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

**Facility** - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

**Interruptible Demand** - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

**Load** - An end-use device or customer that receives power from the electric system.

**Transmission** - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

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Approved: December 4th, 2008
A. Introduction

1. Title: Operating Reserves
2. Number: BAL-STD-002-0
3. Purpose: Regional Reliability Standard to address the Operating Reserve requirements of the Western Interconnection.

4. Applicability

4.1.1 This criterion applies to each Responsible Entity that is (i) a Balancing Authority or a member of a Reserve Sharing Group that does not designate its Reserve Sharing Group as its agent, or (ii) a Reserve Sharing Group. A Responsible Entity that is a Balancing Authority and a member of a Reserve Sharing Group is subject to this criterion only as described in Section A.4.1.2. A Responsible Entity that is a member of a Reserve Sharing Group is not subject to this criterion on an individual basis.

4.1.2 Responsible Entities that are members of a Reserve Sharing Group may designate in writing to WECC a Responsible Entity to act as agent for purposes of this criterion for each such Reserve Sharing Group. Such Reserve Sharing Group agents shall be responsible for all data submission requirements under Section D of this Reliability Agreement. Unless a Reserve Sharing Group agent identifies individual Responsible Entities responsible for noncompliance at the time of data submission, sanctions for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance. If a Responsible Entity that is a member of a Reserve Sharing Group does not designate in writing to WECC a Responsible Entity to act as agent for purposes of this criterion for each such Reserve Sharing Group, such Responsible Entity shall be subject to this criterion on an individual basis.

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1.

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- supply requirements for load variations.
- replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
- meet on-demand obligations.
• replace energy lost due to curtailment of interruptible imports.

a. Minimum Operating Reserve. Each Balancing Authority shall maintain minimum Operating Reserve which is the sum of the following:

(i) Regulating reserve. Sufficient Spinning Reserve, immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet NERC’s Control Performance Criteria (see BAL-001-0).

(ii) Contingency reserve. An amount of Spinning Reserve and Nonspinning Reserve (at least half of which must be Spinning Reserve), sufficient to meet the NERC Disturbance Control Standard BAL-002-0, equal to the greater of:

(a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or

(b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.

The combined unit ramp rate of each Balancing Authority’s on-line, unloaded generating capacity must be capable of responding to the Spinning Reserve requirement of that Balancing Authority within ten minutes.

(iii) Additional reserve for interruptible imports. An amount of reserve, which can be made effective within ten minutes, equal to interruptible imports.

(iv) Additional reserve for on-demand obligations. An amount of reserve, which can be made effective within ten minutes, equal to on-demand obligations to other entities or Balancing Authorities.

b. Acceptable types of Nonspinning Reserve. The Nonspinning Reserve obligations identified in subsections a(ii), a(iii), and a(iv), if any, can be met by use of the following:

(i) interruptible load;

(ii) interruptible exports;

(iii) on-demand rights from other entities or Balancing Authorities;

(iv) Spinning Reserve in excess of requirements in subsections a(i) and a(ii); or

(v) off-line generation which qualifies as Nonspinning Reserve.

c. Knowledge of Operating Reserve. Operating Reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.
d. Restoration of Operating Reserve. After the occurrence of any event necessitating the use of Operating Reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes (Source: WECC Criterion)

C. Measures

WM1.

Except within the first 60 minutes following an event requiring the activation of Operating Reserves, a Responsible Entity identified in Section A.4 must maintain 100% of required Operating Reserve levels based upon data averaged over each clock hour. Following every event requiring the activation of Operating Reserves, a Responsible Entity identified in Section A.4 must re-establish the required Operating Reserve levels within 60 minutes. (Source: Compliance Standard)

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Western Electricity Coordinating Council (WECC)

1.2 Compliance Monitoring Period

At Occurrence and Quarterly

By no later than 5:00 p.m. Mountain Time on the first Business Day following the day on which an instance of non-compliance occurs (or such other date specified in Form A.1(a)), the Responsible Entities identified in Section A.4 shall submit to the WECC office Operating Reserve data in Form A.1(a) (available on the WECC web site) for each such instance of non-compliance. On or before the tenth day of each calendar quarter (or such other date specified in Form A.1(b)), the Responsible Entities identified in Section A.4 (including Responsible Entities with no reported instances of non-compliance) shall submit to the WECC office a completed Operating Reserve summary compliance Form A.1(b) (available on the WECC web site) for the immediately preceding calendar quarter.

1.3 Data Retention

Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

1.4. Additional Compliance Information

For purposes of applying the sanctions specified in Sanction Table for violations of this criterion, the “Sanction Measure” is Average Generation and the “Specified Period” is the most recent calendar month. (Source: Sanctions)

2. Levels of Non-Compliance

Sanction Measure: Average Generation
2.1. **Level 1**: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One instance during a calendar month in which the Balancing Authority’s or the Reserve Sharing Group’s Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve.

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

2.2.1 One instance during a calendar month in which the Balancing Authority’s or the Reserve Sharing Group’s Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve.

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

2.3.1 One instance during a calendar month in which the Balancing Authority’s or the Reserve Sharing Group’s Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve.

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

2.4.1 One instance during a calendar month in which the Balancing Authority’s or the Reserve Sharing Group’s Operating Reserve is less than 70% of the required Operating Reserve.

**E. Regional Differences**

**Version History** – Shows Approval History and Summary of Changes in the Action Field

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Sanction Table

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
<thead>
<tr>
<th>Level of Non-compliance</th>
<th>Number of Occurrences at a Given Level within Specified Period</th>
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<tr>
<td></td>
<td>1</td>
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<tr>
<td>Level 1</td>
<td>Letter (A)</td>
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<tr>
<td>Level 2</td>
<td>Letter (B)</td>
</tr>
<tr>
<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
</tbody>
</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and

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1 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Responsible Entity has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.

DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in this Standard and as set out below:

Area Control Error or ACE means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.

Automatic Generation Control or AGC means equipment that automatically adjusts a Control Area’s generation from a central location to maintain its interchange schedule plus Frequency Bias.

Average Generation means the total MWh generated within the Balancing Authority Operator’s Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).

Business Day means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

Disturbance means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

Extraordinary Contingency shall have the meaning set out in Excuse of Performance, section B.4.c.
**Frequency Bias** means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

**Nonspinning Reserve** means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

**Operating Reserve** means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.

**Spinning Reserve** means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).

**EXCUSE OF PERFORMANCE**

A. **Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

B. **Specific Excuses**

1. **Governmental Order**

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. **Order of Reliability Coordinator**

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply
Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Reliability Agreement. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity
demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

**b.** Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

5. **Participation in Field Testing**

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
A. Introduction

1. Title: Sabotage Reporting
2. Number: CIP-001-1
3. Purpose: Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

4. Applicability
   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Generator Operators.
   4.5. Load Serving Entities.

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements 2 and 3.
M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the applicable, local FBI or RCMP officials to communicate sabotage events (Requirement 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 Time Frame

One or more of the following methods will be used to verify 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 Reliability Coordinator, Transmission Operator, Generator Operator, Distribution Provider, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

If an entity is found non-compliant the entity shall keep information related to the non-compliance 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:**
   
   2.1. **Level 1:** There shall be a separate Level 1 non-compliance, for every one of the following requirements that is in violation:
      
      2.1.1 Does not have procedures for the recognition of and for making its operating personnel aware of sabotage events (R1).
      
      2.1.2 Does not have procedures or guidelines for the communication of information concerning sabotage events to appropriate parties in the Interconnection (R2).
      
      2.1.3 Has not established communications contacts, as specified in R4.
      
      2.2. **Level 2:** Not applicable.
      
      2.3. **Level 3:** Has not provided its operating personnel with sabotage response procedures or guidelines (R3).
      
      2.4. **Level 4:** Not applicable.

**E. Regional Differences**

None indicated.

**Version History**

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<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
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A. Introduction

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

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

3. **Purpose:** NERC Standards CIP-002-2 through CIP-009-2 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

   These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

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

   Standard CIP-002-2 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

4.1. Within the text of Standard CIP-002-2, “Responsible Entity” shall mean:

   4.1.1 Reliability Coordinator.
   4.1.2 Balancing Authority.
   4.1.3 Interchange Authority.
   4.1.4 Transmission Service Provider.
   4.1.5 Transmission Owner.
   4.1.6 Transmission Operator.
   4.1.7 Generator Owner.
   4.1.8 Generator Operator.
   4.1.9 Load Serving Entity.
   4.1.10 NERC.
   4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)
B. Requirements


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

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

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

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

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

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

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

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

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

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

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-2, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

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

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

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

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

M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.
# Version History

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<td>1</td>
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<td>2</td>
<td>05/06/09</td>
<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.</td>
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Adopted by NERC Board of Trustees: May 6, 2009
A. Introduction

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

2. **Number:** CIP-002-3

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

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

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

Standard CIP-002-3 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-002-3, “Responsible Entity” shall mean:

   4.1.1 Reliability Coordinator.
   4.1.2 Balancing Authority.
   4.1.3 Interchange Authority.
   4.1.4 Transmission Service Provider.
   4.1.5 Transmission Owner.
   4.1.6 Transmission Operator.
   4.1.7 Generator Owner.
   4.1.8 Generator Operator.
   4.1.9 Load Serving Entity.
   4.1.10 NERC.
   4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3:

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

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

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)
B. Requirements


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

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

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

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

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

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

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

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

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

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

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

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

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

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

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

C. Measures
M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

      1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

      1.1.2 ERO for Regional Entity.

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

   1.2. Compliance Monitoring Period and Reset Time Frame

      Not applicable.

   1.3. Compliance Monitoring and Enforcement Processes

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

   1.4. Data Retention

      1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

      1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

   1.5. Additional Compliance Information

      1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.
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A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-2
3. **Purpose:** Standard CIP-003-2 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.
4. **Applicability:**
   4.1. Within the text of Standard CIP-003-2, “Responsible Entity” shall mean:
      4.1.1 Reliability Coordinator.
      4.1.2 Balancing Authority.
      4.1.3 Interchange Authority.
      4.1.4 Transmission Service Provider.
      4.1.5 Transmission Owner.
      4.1.6 Transmission Operator.
      4.1.7 Generator Owner.
      4.1.8 Generator Operator.
      4.1.9 Load Serving Entity.
      4.1.10 NERC.
      4.1.11 Regional Entity.
   4.2. The following are exempt from Standard CIP-003-2:
      4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
      4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-2 Requirement R2.
5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

**R1.1.** The cyber security policy addresses the requirements in Standards CIP-002-2 through CIP-009-2, including provision for emergency situations.
R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

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

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity’s implementation of, and adherence to, Standards CIP-002-2 through CIP-009-2.

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

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

R2.3. Where allowed by Standards CIP-002-2 through CIP-009-2, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

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

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

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

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

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

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-2, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

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

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

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

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

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.
R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

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

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

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

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2. ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. **Data Retention**

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. **Additional Compliance Information**

1.5.1 None

2. **Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

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<td>Adopted by NERC Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Cyber Security — Security Management Controls
2. Number: CIP-003-3
3. Purpose: Standard CIP-003-3 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.
4. Applicability:
   4.1. Within the text of Standard CIP-003-3, “Responsible Entity” shall mean:
      4.1.1 Reliability Coordinator.
      4.1.2 Balancing Authority.
      4.1.3 Interchange Authority.
      4.1.4 Transmission Service Provider.
      4.1.5 Transmission Owner.
      4.1.6 Transmission Operator.
      4.1.7 Generator Owner.
      4.1.8 Generator Operator.
      4.1.9 Load Serving Entity.
      4.1.10 NERC.
      4.1.11 Regional Entity.
   4.2. The following are exempt from Standard CIP-003-3:
      4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
      4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-3 Requirement R2.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

   R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management’s commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:
      R1.1. The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.

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

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

R2.  Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity’s implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.

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

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

R2.3.  Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates.  These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4.  The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

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

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

R3.2.  Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

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

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

R4.1.  The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

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

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

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

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

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

Approved by Board of Trustees: December 16, 2009
R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

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

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

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

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

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<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.</td>
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<td>3</td>
<td>12/16/09</td>
<td>Approved by the NERC Board of Trustees</td>
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A. Introduction

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

4. Applicability:

4.1. Within the text of Standard CIP-004-2, “Responsible Entity” shall mean:

4.1.1 Reliability Coordinator.
4.1.2 Balancing Authority.
4.1.3 Interchange Authority.
4.1.4 Transmission Service Provider.
4.1.5 Transmission Owner.
4.1.6 Transmission Operator.
4.1.7 Generator Owner.
4.1.8 Generator Operator.
4.1.9 Load Serving Entity.
4.1.10 NERC.
4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-004-2:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

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

R2. Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.

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

R2.2.1. The proper use of Critical Cyber Assets;
R2.2.2. Physical and electronic access controls to Critical Cyber Assets;
R2.2.3. The proper handling of Critical Cyber Asset information; and,
R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

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

R3. Personnel Risk Assessment — The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency.

The personnel risk assessment program shall at a minimum include:

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

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

R3.3. The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-2.

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

R4.1. The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.
R4.2. The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

C. Measures

M1. The Responsible Entity shall make available documentation of its security awareness and reinforcement program as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of its cyber security training program, review, and records as specified in Requirement R2.

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

M4. The Responsible Entity shall make available documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

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

1.4.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.
1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

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<td>D.2.2.4 — Insert the phrase “for cause” as intended. “One instance of personnel termination for cause…”</td>
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<td>06/01/06</td>
<td>D.2.1.4 — Change “access control rights” to “access rights.”</td>
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<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Reference to emergency situations. Modification to R1 for the Responsible Entity to establish, document, implement, and maintain the awareness program. Modification to R2 for the Responsible Entity to establish, document, implement, and maintain the training program; also stating the requirements for the cyber security training program. Modification to R3 Personnel Risk Assessment to clarify that it pertains to personnel having authorized cyber or authorized unescorted physical access to “Critical Cyber Assets”. Removal of 90 day window to complete training and 30 day window to complete personnel risk assessments. Changed compliance monitor to Compliance Enforcement Authority.</td>
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<td>Adopted by NERC Board of Trustees</td>
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A. Introduction

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

4. Applicability:
   4.1. Within the text of Standard CIP-004-3, “Responsible Entity” shall mean:
       4.1.1 Reliability Coordinator.
       4.1.2 Balancing Authority.
       4.1.3 Interchange Authority.
       4.1.4 Transmission Service Provider.
       4.1.5 Transmission Owner.
       4.1.6 Transmission Operator.
       4.1.7 Generator Owner.
       4.1.8 Generator Operator.
       4.1.9 Load Serving Entity.
       4.1.10 NERC.
       4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-004-3:
       4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
       4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
       4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as:
   • Direct communications (e.g., emails, memos, computer based training, etc.);
   • Indirect communications (e.g., posters, intranet, brochures, etc.);
   • Management support and reinforcement (e.g., presentations, meetings, etc.).
R2. Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.

R2.2. Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:

R2.2.1. The proper use of Critical Cyber Assets;
R2.2.2. Physical and electronic access controls to Critical Cyber Assets;
R2.2.3. The proper handling of Critical Cyber Asset information; and,
R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

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

R3. Personnel Risk Assessment — The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency.

The personnel risk assessment program shall at a minimum include:

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

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

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

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

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

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

M1. The Responsible Entity shall make available documentation of its security awareness and reinforcement program as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of its cyber security training program, review, and records as specified in Requirement R2.

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

M4. The Responsible Entity shall make available documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

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

1.4.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances
None identified.

Version History

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<td>01/16/06</td>
<td>D.2.2.4 — Insert the phrase “for cause” as intended. “One instance of personnel termination for cause…”</td>
<td>03/24/06</td>
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<td>06/01/06</td>
<td>D.2.1.4 — Change “access control rights” to “access rights.”</td>
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<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Reference to emergency situations. Modification to R1 for the Responsible Entity to establish, document, implement, and maintain the awareness program. Modification to R2 for the Responsible Entity to establish, document, implement, and maintain the training program; also stating the requirements for the cyber security training program. Modification to R3 Personnel Risk Assessment to clarify that it pertains to personnel having authorized cyber or authorized unescorted physical access to “Critical Cyber Assets”. Removal of 90 day window to complete training and 30 day window to complete personnel risk assessments. Changed compliance monitor to Compliance Enforcement Authority.</td>
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A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-2
3. **Purpose:** Standard CIP-005-2 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability**
   4.1. Within the text of Standard CIP-005-2, “Responsible Entity” shall mean:
      
      4.1.1 Reliability Coordinator.
      
      4.1.2 Balancing Authority.
      
      4.1.3 Interchange Authority.
      
      4.1.4 Transmission Service Provider.
      
      4.1.5 Transmission Owner.
      
      4.1.6 Transmission Operator.
      
      4.1.7 Generator Owner.
      
      4.1.8 Generator Operator.
      
      4.1.9 Load Serving Entity.
      
      4.1.10 NERC.
      
      4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-005-2:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
   
   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
   
   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

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

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

   R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.
R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-2.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirement R3; Standard CIP-007-2 Requirements R1 and R3 through R9; Standard CIP-008-2; and Standard CIP-009-2.

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

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

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

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

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

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

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

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

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-2 Requirement R4.

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

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

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.
R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

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

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

R4.1. A document identifying the vulnerability assessment process;
R4.2. A review to verify that only ports and services required for operations at these access points are enabled;
R4.3. The discovery of all access points to the Electronic Security Perimeter;
R4.4. A review of controls for default accounts, passwords, and network management community strings;
R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-2.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-2 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-2 at least annually.

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

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance
1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-2, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-2 from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

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<td>Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity shall “implement and maintain” a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.</td>
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A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-3
3. **Purpose:** Standard CIP-005-3 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability**

4.1. Within the text of Standard CIP-005-3, “Responsible Entity” shall mean:

4.1.1 Reliability Coordinator.
4.1.2 Balancing Authority.
4.1.3 Interchange Authority.
4.1.4 Transmission Service Provider.
4.1.5 Transmission Owner.
4.1.6 Transmission Operator.
4.1.7 Generator Owner.
4.1.8 Generator Operator.
4.1.9 Load Serving Entity.
4.1.10 NERC.
4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-005-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

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

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

**R1.2.** For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.
R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.

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

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

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

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

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

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

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

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

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.

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

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

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.
R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

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

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

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

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

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

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

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

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.

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

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

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process
1.1. **Compliance Enforcement Authority**

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. **Compliance Monitoring Period and Reset Time Frame**

Not applicable.

1.3. **Compliance Monitoring and Enforcement Processes**

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

1.4. **Data Retention**

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-3, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-3 from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. **Additional Compliance Information**

2. **Violation Severity Levels (To be developed later.)**

E. **Regional Variances**

None identified.

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shall “implement and maintain” a procedure for securing dial-up access to the Electronic Security Perimeter(s).

Changed compliance monitor to Compliance Enforcement Authority.

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A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets
2. Number: CIP-006-1a
3. Purpose: Standard CIP-006 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. Applicability:

4.1. Within the text of Standard CIP-006, “Responsible Entity” shall mean:
   4.1.1 Reliability Coordinator.
   4.1.2 Balancing Authority.
   4.1.3 Interchange Authority.
   4.1.4 Transmission Service Provider.
   4.1.5 Transmission Owner.
   4.1.6 Transmission Operator.
   4.1.7 Generator Owner.
   4.1.8 Generator Operator.
   4.1.9 Load Serving Entity.
   4.1.10 NERC.
   4.1.11 Regional Reliability Organizations.

4.2. The following are exempt from Standard CIP-006:
   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. Effective Date: June 1, 2006

B. Requirements

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

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

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

   R1.2. Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.
R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

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

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

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

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


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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**C. Measures**

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

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

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

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

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

Access logs as specified in Requirement R5.

Documentation as specified in Requirement R6.

**D. Compliance**

1. **Compliance Monitoring Process**

1.1. **Compliance Monitoring Responsibility**

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

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

1.2. **Compliance Monitoring Period and Reset Time Frame**

Annually.
1.3. **Data Retention**

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

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

1.4. **Additional Compliance Information**

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

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

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

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

2. **Levels of Noncompliance**

2.1. **Level 1:**

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

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

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

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

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

2.1.6 One required document does not exist.

2.2. **Level 2:**

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

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

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

2.2.4 More than one required document does not exist.

2.3. **Level 3:**

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

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

2.3.3 No logs of monitored physical access are retained.
2.4. Level 4:

2.4.1 No physical security plan exists; or,

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

2.4.3 No maintenance or testing program exists.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R1.1 and additional Compliance Information Section 1.4.4 (February 12, 2008).

Version History

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Appendix 1

Interpretation of Requirement R1.1.

Request: Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.

Interpretation:
Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a “six-wall” border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

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

1. Title: Cyber Security — Physical Security of Critical Cyber Assets
2. Number: CIP-006-1b
3. Purpose: Standard CIP-006 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. Applicability:
4.1. Within the text of Standard CIP-006, “Responsible Entity” shall mean:
   4.1.1 Reliability Coordinator.
   4.1.2 Balancing Authority.
   4.1.3 Interchange Authority.
   4.1.4 Transmission Service Provider.
   4.1.5 Transmission Owner.
   4.1.6 Transmission Operator.
   4.1.7 Generator Owner.
   4.1.8 Generator Operator.
   4.1.9 Load Serving Entity.
   4.1.10 NERC.
   4.1.11 Regional Reliability Organizations.

4.2. The following are exempt from Standard CIP-006:
   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. Effective Date: June 1, 2006

B. Requirements

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

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:
   R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
   R1.2. Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.
R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

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

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

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

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


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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Measures

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

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

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

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

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

Access logs as specified in Requirement R5.

Documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.
1.3. Data Retention

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

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

1.4. Additional Compliance Information

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

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

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

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

2. Levels of Noncompliance

2.1. Level 1:

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

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

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

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

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

2.1.6 One required document does not exist.

2.2. Level 2:

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

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

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

2.2.4 More than one required document does not exist.

2.3. Level 3:

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

2.3.2 Access to between 26% and 50% of a Responsible Entity’s total number of physical security perimeters is not controlled, monitored, and logged; or,
2.3.3 No logs of monitored physical access are retained.

2.4. Level 4:

2.4.1 No physical security plan exists; or,

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

2.4.3 No maintenance or testing program exists.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R1.1 and additional Compliance Information Section 1.4.4 (February 12, 2008).

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Appendix 1

Interpretation of Requirement R1.1.

Request:  Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.

Interpretation:
Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a “six-wall” border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.
Appendix 2

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?

2. Does the term, “time of access” mean logging when the person entered the facility or does it mean logging the entry/exit time and “length” of time the person had access to the critical asset?

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term “time of access” refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

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

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

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

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

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

2. Number: CIP-006-2

3. Purpose: Standard CIP-006-2 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. Applicability:
   4.1. Within the text of Standard CIP-006-2, “Responsible Entity” shall mean:
       4.1.1 Reliability Coordinator.
       4.1.2 Balancing Authority.
       4.1.3 Interchange Authority.
       4.1.4 Transmission Service Provider.
       4.1.5 Transmission Owner.
       4.1.6 Transmission Operator.
       4.1.7 Generator Owner.
       4.1.8 Generator Operator.
       4.1.9 Load Serving Entity.
       4.1.10 NERC.
       4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-006-2:
       4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
       4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
       4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

   R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

   R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.
R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-2 Requirement R4.

R1.6. Continuous escorted access within the Physical Security Perimeter of personnel not authorized for unescorted access.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirements R4 and R5; Standard CIP-007-2; Standard CIP-008-2; and Standard CIP-009-2.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-2. One or more of the following monitoring methods shall be used:
• Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.

• Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

• Computerized Logging: Electronic logs produced by the Responsible Entity’s selected access control and monitoring method.

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

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

R7. Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.
M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

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

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-2 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.
### Version History

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<td>Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, <a href="#">implemented</a> and approved by the senior manager. Revised the wording in R1.2 to identify all “physical” access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.</td>
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Adopted by NERC Board of Trustees: May 6, 2009
A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets
2. Number: CIP-006-2c
3. Purpose: Standard CIP-006-2 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. Applicability:

4.1. Within the text of Standard CIP-006-2, “Responsible Entity” shall mean:

4.1.1 Reliability Coordinator.
4.1.2 Balancing Authority.
4.1.3 Interchange Authority.
4.1.4 Transmission Service Provider.
4.1.5 Transmission Owner.
4.1.6 Transmission Operator.
4.1.7 Generator Owner.
4.1.8 Generator Operator.
4.1.9 Load Serving Entity.
4.1.10 NERC.
4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-006-2:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.
R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

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

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-2 Requirement R4.

R1.6. Continuous escorted access within the Physical Security Perimeter of personnel not authorized for unescorted access.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-2; Standard CIP-004-2 Requirement R3; Standard CIP-005-2 Requirements R2 and R3; Standard CIP-006-2 Requirements R4 and R5; Standard CIP-007-2; Standard CIP-008-2; and Standard CIP-009-2.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized
access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-2. One or more of the following monitoring methods shall be used:

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

- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity’s selected access control and monitoring method.

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

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

R7. Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-2.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.
M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.
1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-2 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

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<td>2</td>
<td>05/06/09</td>
<td>Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented and approved by the senior manager. Revised the wording in R1.2 to identify all “physical” access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.</td>
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<td>1a</td>
<td>February 12, 2008</td>
<td>Added Appendix 1: Interpretation of R1 and Additional Compliance Information Section 1.4.4 as adopted by the Board of Trustees</td>
</tr>
<tr>
<td>1b</td>
<td>August 5, 2009</td>
<td>Added Appendix 2: Interpretation of R4 as adopted by the Board of Trustees</td>
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Adopted by NERC Board of Trustees: May 6, 2009
SCE&G Adopted by Board of Trustees: February 12, 2008
USCOE Adopted by Board of Trustees: August 5, 2009
PacifiCorp Adopted by Board of Trustees: February 16, 2010
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Appendix 1

Interpretation of Requirement R1.1.

Request: Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.

Interpretation:
Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a “six-wall” border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.
Appendix 2

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?

2. Does the term, “time of access” mean logging when the person entered the facility or does it mean logging the entry/exit time and “length” of time the person had access to the critical asset?

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term “time of access” refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

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

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

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

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

### Requirement Number and Text of Requirement

<table>
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<tr>
<td>R1.</td>
<td>Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:</td>
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<td></td>
<td>R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.</td>
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### Question

If a completely enclosed border cannot be created, what does the phrase, “to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption?

Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?

### Response

For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are “physical in nature.” The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.
A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets
2. Number: CIP-006-3
3. Purpose: Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-006-3, “Responsible Entity” shall mean:

4.1.1 Reliability Coordinator
4.1.2 Balancing Authority
4.1.3 Interchange Authority
4.1.4 Transmission Service Provider
4.1.5 Transmission Owner
4.1.6 Transmission Operator
4.1.7 Generator Owner
4.1.8 Generator Operator
4.1.9 Load Serving Entity
4.1.10 NERC
4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).
R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:
• Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.

• Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

• Computerized Logging: Electronic logs produced by the Responsible Entity’s selected access control and monitoring method.

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

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

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.
M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

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

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.
## Version History

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| 2       |            | Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.  
          |            | Replaced the RRO with RE as a responsible entity.  
          |            | Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented, and approved by the senior manager.  
          |            | Revised the wording in R1.2 to identify all “physical” access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2.  
          |            | Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter.  
          |            | The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements.  
          |            | Changed the Compliance Monitor to Compliance Enforcement Authority.                                                                                                                                 |
| 3       | 11/18/2009 | Updated version numbers from -2 to -3  
          |            | Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009.  
          |            | In Requirement R7, the term “Responsible Entity” was capitalized.                                                                                                                                   |
| 3       | 12/16/09   | Approved by NERC Board of Trustees                                                                                                                                                                   |
A. Introduction

1. Title: Cyber Security — Systems Security Management
2. Number: CIP-007-2a
3. Purpose: Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. Applicability:

4.1. Within the text of Standard CIP-007-2, “Responsible Entity” shall mean:
   4.1.1 Reliability Coordinator.
   4.1.2 Balancing Authority.
   4.1.3 Interchange Authority.
   4.1.4 Transmission Service Provider.
   4.1.5 Transmission Owner.
   4.1.6 Transmission Operator.
   4.1.7 Generator Owner.
   4.1.8 Generator Operator.
   4.1.9 Load Serving Entity.
   4.1.10 NERC.
   4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-007-2:
   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: April 1, 2010

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-2, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.
R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

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

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

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

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

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

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-2 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

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

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

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

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

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

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

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

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-2 Requirement R5.
R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-2 Requirement R5 and Standard CIP-004-2 Requirement R4.

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

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

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

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

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

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

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

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

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

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

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

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-2.

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

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

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-2.
R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

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

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

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

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

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

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

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

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-2 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance
1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-2 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

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<td>Added Appendix 2 — Interpretation of R2 approved by BOT on November 5, 2009</td>
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### Requirement Number and Text of Requirement

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<tr>
<td>R2. The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.</td>
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### Question

Does the term "port" mean a physical (hardware) or a logical (software) connection to a computer?

### Response

The drafting team interprets the term “ports” used as part of the phrase “ports and services” to refer to logical ports, e.g., Transmission Control Protocol (TCP) ports, where interface with communication services occurs.
A. Introduction

1. Title: Cyber Security — Systems Security Management
2. Number: CIP-007-3
3. Purpose: Standard CIP-007-3 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:
   4.1. Within the text of Standard CIP-007-3, “Responsible Entity” shall mean:
      4.1.1 Reliability Coordinator.
      4.1.2 Balancing Authority.
      4.1.3 Interchange Authority.
      4.1.4 Transmission Service Provider.
      4.1.5 Transmission Owner.
      4.1.6 Transmission Operator.
      4.1.7 Generator Owner.
      4.1.8 Generator Operator.
      4.1.9 Load Serving Entity.
      4.1.10 NERC.
      4.1.11 Regional Entity.
   4.2. The following are exempt from Standard CIP-007-3:
      4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
      4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.
R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

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

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

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

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

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

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

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

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

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

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

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

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

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

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.
R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.
R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

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

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

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

R8.1. A document identifying the vulnerability assessment process;
R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;
R8.3. A review of controls for default accounts; and,
R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process
1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-3 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

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<td>Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.</td>
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A. Introduction

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

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

3. **Purpose:** Standard CIP-008-2 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. **Applicability**

   4.1. Within the text of Standard CIP-008-2, “Responsible Entity” shall mean:

      4.1.1 Reliability Coordinator.

      4.1.2 Balancing Authority.

      4.1.3 Interchange Authority.

      4.1.4 Transmission Service Provider.

      4.1.5 Transmission Owner.

      4.1.6 Transmission Operator.

      4.1.7 Generator Owner.

      4.1.8 Generator Operator.

      4.1.9 Load Serving Entity.

      4.1.10 NERC.

      4.1.11 Regional Entity.

   4.2. The following are exempt from Standard CIP-008-2:

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

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

      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

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

   **R1.2.** Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.
R1.3. Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.

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

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

R1.6. Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident. Testing the Cyber Security Incident response plan does not require removing a component or system from service during the test.

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

C. Measures

M1. The Responsible Entity shall make available its Cyber Security Incident response plan as indicated in Requirement R1 and documentation of the review, updating, and testing of the plan.

M2. The Responsible Entity shall make available all documentation as specified in Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention
1.4.1 The Responsible Entity shall keep documentation other than that required for reportable Cyber Security Incidents as specified in Standard CIP-008-2 for the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

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

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

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

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A. Introduction

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

2. **Number:** CIP-008-3

3. **Purpose:** Standard CIP-008-3 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008-23 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability**

4.1. Within the text of Standard CIP-008-3, “Responsible Entity” shall mean:

4.1.1. Reliability Coordinator.

4.1.2. Balancing Authority.

4.1.3. Interchange Authority.

4.1.4. Transmission Service Provider.

4.1.5. Transmission Owner.

4.1.6. Transmission Operator.

4.1.7. Generator Owner.

4.1.8. Generator Operator.

4.1.9. Load Serving Entity.

4.1.10. NERC.

4.1.11. Regional Entity.

4.2. The following are exempt from Standard CIP-008-3:

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

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

4.2.3. Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

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

R1.2. Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.
R1.3. Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.

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

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

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

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

C. Measures

M1. The Responsible Entity shall make available its Cyber Security Incident response plan as indicated in Requirement R1 and documentation of the review, updating, and testing of the plan.

M2. The Responsible Entity shall make available all documentation as specified in Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation other than that required for reportable Cyber Security Incidents as specified in Standard CIP-008-3 for the previous full calendar year unless directed by its Compliance Enforcement
Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

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

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

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

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<td>Updated Version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.</td>
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A. Introduction

1. Title: Cyber Security — Recovery Plans for Critical Cyber Assets
2. Number: CIP-009-2
3. Purpose: Standard CIP-009-2 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009-2 should be read as part of a group of standards numbered Standards CIP-002-2 through CIP-009-2.

4. Applicability:

   4.1. Within the text of Standard CIP-009-2, “Responsible Entity” shall mean:

      4.1.1 Reliability Coordinator
      4.1.2 Balancing Authority
      4.1.3 Interchange Authority
      4.1.4 Transmission Service Provider
      4.1.5 Transmission Owner
      4.1.6 Transmission Operator
      4.1.7 Generator Owner
      4.1.8 Generator Operator
      4.1.9 Load Serving Entity
      4.1.10 NERC
      4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-009-2:

      4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
      4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-2, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

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

   R1.1. Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).
   R1.2. Define the roles and responsibilities of responders.
R2. Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.

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

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

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

C. Measures

M1. The Responsible Entity shall make available its recovery plan(s) as specified in Requirement R1.

M2. The Responsible Entity shall make available its records documenting required exercises as specified in Requirement R2.

M3. The Responsible Entity shall make available its documentation of changes to the recovery plan(s), and documentation of all communications, as specified in Requirement R3.

M4. The Responsible Entity shall make available its documentation regarding backup and storage of information as specified in Requirement R4.

M5. The Responsible Entity shall make available its documentation of testing of backup media as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-009-2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

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A. Introduction

1. Title: Cyber Security — Recovery Plans for Critical Cyber Assets
2. Number: CIP-009-3
3. Purpose: Standard CIP-009-3 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:
   4.1. Within the text of Standard CIP-009-3, “Responsible Entity” shall mean:
      4.1.1 Reliability Coordinator
      4.1.2 Balancing Authority
      4.1.3 Interchange Authority
      4.1.4 Transmission Service Provider
      4.1.5 Transmission Owner
      4.1.6 Transmission Operator
      4.1.7 Generator Owner
      4.1.8 Generator Operator
      4.1.9 Load Serving Entity
      4.1.10 NERC
      4.1.11 Regional Entity
   4.2. The following are exempt from Standard CIP-009-3:
      4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
      4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
      4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:
   R1.1. Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).
   R1.2. Define the roles and responsibilities of responders.

R2. Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.
R3. Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.

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

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

C. Measures

M1. The Responsible Entity shall make available its recovery plan(s) as specified in Requirement R1.

M2. The Responsible Entity shall make available its records documenting required exercises as specified in Requirement R2.

M3. The Responsible Entity shall make available its documentation of changes to the recovery plan(s), and documentation of all communications, as specified in Requirement R3.

M4. The Responsible Entity shall make available its documentation regarding backup and storage of information as specified in Requirement R4.

M5. The Responsible Entity shall make available its documentation of testing of backup media as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

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

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

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

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-009-3 from the previous full calendar year unless directed by its Compliance
Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

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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: May 13, 2009

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.


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 then 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**

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<td>April 6, 2007</td>
<td>Requirement 1, added the word “for” between “facilities” and “the exchange.”</td>
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<td>1.1</td>
<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to “1.1”</td>
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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:** Communication and Coordination
2. **Number:** COM-002-2
3. **Purpose:** To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

4. **Applicability**
   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Generator Operators.

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

B. Requirements

**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.

**R1.1.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.

**R2.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

C. Measures

**M1.** Each Transmission Operator, Balancing Authority and Generator Operator shall have communication facilities (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators and shall have and provide as evidence, a list of communication facilities or other equivalent evidence that confirms that the communications have been provided to address a real-time emergency condition. (Requirement 1, part 1)

**M2.** The Balancing Authority and Transmission Operator 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 notified its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators of a
condition that could threaten the reliability of its area or when firm load shedding was anticipated. (Requirement 1.1)

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 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 Balancing Authority, Transmission Operator and Generator Operator shall keep evidence of compliance for the previous two calendar years plus the current year. (Measure 1)

Each Balancing Authority and Transmission Operator shall keep 90 days of historical data. (Measure 2).

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 Transmission Operator and Balancing Authority:
2.1. **Level 1**: Not applicable.
2.2. **Level 2**: Not applicable.
2.3. **Level 3**: Not applicable.
2.4. **Level 4**: Communication did not occur as specified in R1.1.

3. **Levels of Non-Compliance for Generator Operator**:
   3.1. **Level 1**: Not applicable.
   3.2. **Level 2**: Not applicable.
   3.3. **Level 3**: Not applicable.
   3.4. **Level 4**: Communication facilities are not provided to address a real-time emergency condition as specified in R1.

**E. Regional Differences**

None identified.

**Version History**

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A. Introduction

1. Title: Emergency Operations Planning
2. Number: EOP-001-0
3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.2. Transmission Operators.

5. Effective Date: April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.
R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes
The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention
Current plan available at all times.

1.4. Additional Compliance Information
Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-0 has not been addressed in the emergency plans.
2.2. **Level 2:** Two of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.3. **Level 3:** Three of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.4. **Level 4:** Four or more of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans or a plan does not exist.

### E. Regional Differences

None identified.

### Version History

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</table>
Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system’s own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.
A. Introduction

1. Title: Emergency Operations Planning
2. Number: EOP-001-1
3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability
   4.2. Transmission Operators.

5. Proposed Effective Dates:
   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after Board of Trustee adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:
   R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.
   R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
   R2.3. Develop, maintain, and implement a set of plans for load shedding.
   R2.4. Develop, maintain, and implement a set of plans for system restoration.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:
   R3.1. Communications protocols to be used during emergencies.
   R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.
   R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.
   R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame
The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention
Current plan available at all times.

1.4. Additional Compliance Information
Not specified.
2. Violation Severity Levels:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.</td>
</tr>
<tr>
<td>R2</td>
<td>The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority has demonstrated the existence of emergency plans but the plans are not maintained.</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.</td>
</tr>
<tr>
<td>R2.1</td>
<td>The Transmission Operator or Balancing Authority’s emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.</td>
</tr>
<tr>
<td>R2.2</td>
<td>The Transmission Operator or Balancing Authority’s plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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</tr>
<tr>
<td>R2.3</td>
<td>The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.</td>
</tr>
<tr>
<td>R2.4</td>
<td>The Transmission Operator or Balancing Authority’s system restoration plans are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority’s system restoration plans are partially compliant with the requirement but are not maintained.</td>
<td>The Transmission Operator or Balancing Authority’s restoration plans are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for system restoration.</td>
</tr>
<tr>
<td>R3</td>
<td>The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.</td>
</tr>
<tr>
<td>R3.1</td>
<td>The Transmission Operator or Balancing Authority’s communication protocols included in the emergency plan are missing minor program/procedural elements.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.</td>
</tr>
<tr>
<td>R3.2</td>
<td>The Transmission Operator or Balancing Authority’s list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.</td>
<td>The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.</td>
</tr>
<tr>
<td>Requirement</td>
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<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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<tr>
<td>-------------</td>
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</tr>
<tr>
<td>R3.3</td>
<td>The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.</td>
</tr>
<tr>
<td>R3.4</td>
<td>The Transmission Operator or Balancing Authority’s emergency plan does not include staffing levels for the emergency</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R4</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 90% or more of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 70% to 90% of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with between 50% to 70% of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 50% or less of the number of sub-components.</td>
</tr>
<tr>
<td>R5</td>
<td>The Transmission Operator and Balancing Authority is missing minor program/procedural elements.</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review one of its emergency plans</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of its neighboring Balancing Authorities.</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.</td>
</tr>
<tr>
<td>R6</td>
<td>The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.</td>
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<tr>
<td>R6.1</td>
<td>The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>R6.2</td>
<td>The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>R6.3</td>
<td>The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R6.4</td>
<td>The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
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</table>
### E. Regional Differences

None identified.

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<td>Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels</td>
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<td>Corrected typographical errors in BOT approved version of VSLs</td>
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Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system’s own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

A. Introduction

1. Title: Emergency Operations Planning
2. Number: EOP-001-2
3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.2. Transmission Operators.

5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done. Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.
2. **Violation Severity Levels:**

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<th>Moderate</th>
<th>High</th>
<th>Severe</th>
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<td>R1</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.</td>
<td>The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.</td>
</tr>
<tr>
<td>R2</td>
<td>The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.</td>
</tr>
<tr>
<td>R2.1</td>
<td>The Transmission Operator or Balancing Authority’s emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.</td>
</tr>
<tr>
<td>R2.2</td>
<td>The Transmission Operator or Balancing Authority’s plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.</td>
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<td>Requirement</td>
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<tr>
<td>R2.3</td>
<td>The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.</td>
<td>The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.</td>
<td>The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.</td>
<td>The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.</td>
</tr>
<tr>
<td>R3</td>
<td>The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.</td>
<td>The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.</td>
</tr>
<tr>
<td>R3.1</td>
<td>The Transmission Operator or Balancing Authority’s communication protocols included in the emergency plan are missing minor program/procedural elements.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.</td>
</tr>
<tr>
<td>R3.2</td>
<td>The Transmission Operator or Balancing Authority’s list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.</td>
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<td>R3.3</td>
<td>The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.</td>
</tr>
<tr>
<td>R3.4</td>
<td>The Transmission Operator or Balancing Authority’s emergency plan does not include staffing levels for the emergency</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R4</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 90% or more of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 70% to 90% of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with between 50% to 70% of the number of sub-components.</td>
<td>The Transmission Operator and Balancing Authority’s emergency plan has complied with 50% or less of the number of sub-components</td>
</tr>
<tr>
<td>R5</td>
<td>The Transmission Operator and Balancing Authority is missing minor program/procedural elements.</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.</td>
<td>The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.</td>
</tr>
<tr>
<td>R6</td>
<td>The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.</td>
<td>The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.</td>
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<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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</tr>
<tr>
<td>R6.1</td>
<td>The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R6.2</td>
<td>The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>R6.3</td>
<td>The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>R6.4</td>
<td>The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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E. Regional Differences

None identified.

Version History

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<td>1</td>
<td>October 17, 2008</td>
<td>Deleted R2</td>
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<td>Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels</td>
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<td>Corrected typographical errors in BOT approved version of VSLs</td>
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<td>To be determined</td>
<td>Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.</td>
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<td>2</td>
<td>August 8, 2009</td>
<td>Adopted by NERC Board of Trustees: August 5, 2009</td>
<td>Revised</td>
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Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system’s own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.
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**
   - 4.2. Reliability Coordinators.
   - 4.3. Load-Serving Entities.
5. **Effective Date:** May 13, 2009

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**

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<tr>
<td>1</td>
<td>September 19, 2006</td>
<td>Changes R7. to refer to “Requirement 6” instead of “Requirement 7”</td>
<td>Errata</td>
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<td>2</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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<td>2</td>
<td>November 1, 2006</td>
<td>Corrected numbering in Section A.4. “Applicability.”</td>
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<td>October 1, 2007</td>
<td>Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities”</td>
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<td>2.1</td>
<td>October 29, 2008</td>
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<td>2.1</td>
<td>May 13, 2009</td>
<td>FERC Approved</td>
<td>Revised</td>
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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 contracts\(^1\).
  - 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

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\(^1\) 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.
A. Introduction

1. Title: Load Shedding Plans
2. Number: EOP-003-1
3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.
4. Applicability
   4.1. Transmission Operators.
   4.2. Balancing Authorities.
5. Effective Date: January 1, 2007

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.
C. Measures

M1. Each Transmission Operator and Balancing Authority that has or directs the deployment of undervoltage and/or underfrequency load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

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 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 noncompliance.

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

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.

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

2.4.1 Does not have an automatic load shedding plan as specified in R2.

2.4.2 Does not have manual load shedding plans as specified in R8.

E. **Regional Differences**

None identified.

**Version History**

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<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
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<td>Effective Date</td>
<td>New</td>
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<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
</tr>
<tr>
<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Disturbance Reporting
2. Number: EOP-004-1
3. Purpose: Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

4. Applicability
   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Generator Operators.
   4.5. Load Serving Entities.
   4.6. Regional Reliability Organizations.

5. Effective Date: January 1, 2007

B. Requirements

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

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

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

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

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

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

**R3.4.** If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

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

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

**C. Measures**

**M1.** The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1)

**M2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.

**M3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident 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 confirm that it provided information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)
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 Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving 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 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, regional reporting procedure as evidence of compliance. (Measure 1)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

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

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

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: No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1.

3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity:

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

3.1.1 Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

3.1.2 Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

3.1.3 Failed to prepare a final report within 60 days as specified in R3.4

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable

3.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

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<th>Action</th>
<th>Change Tracking</th>
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<td>Adopted by Board of Trustees</td>
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<td>1</td>
<td>March 22, 2007</td>
<td>Updated Department of Energy link and references to Form OE-411</td>
<td>Errata</td>
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</tbody>
</table>
Introduction

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

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

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.

2. The occurrence of an interconnected system separation or system islanding or both.

3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.

4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or
   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.

7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.

8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.
### NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

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

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

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

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

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

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

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

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

An updated form OE-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: http://www.oe.netl.doe.gov/oe417.aspx.
### Table 1-EOP-004-0
Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies

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<th>Threshold</th>
<th>Report Required</th>
<th>Time</th>
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<tbody>
<tr>
<td>1</td>
<td>Uncontrolled loss of Firm System Load</td>
<td>$\geq 300$ MW – 15 minutes or more</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Load Shedding</td>
<td>$\geq 100$ MW under emergency operational policy</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Voltage Reductions</td>
<td>$3%$ or more – applied system-wide</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Public Appeals</td>
<td>Emergency conditions to reduce demand</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Physical sabotage, terrorism or vandalism</td>
<td>On physical security systems – suspected or real</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
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</tr>
<tr>
<td>6</td>
<td>Cyber sabotage, terrorism or vandalism</td>
<td>If the attempt is believed to have or did happen</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
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<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Fuel supply emergencies</td>
<td>Fuel inventory or hydro storage levels $\leq 50%$ of normal</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
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<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
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<tr>
<td>8</td>
<td>Loss of electric service</td>
<td>$\geq 50,000$ for 1 hour or more</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
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<td></td>
<td></td>
<td></td>
<td>OE – Sch-2</td>
<td></td>
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<tr>
<td>9</td>
<td>Complete operation failure of electrical system</td>
<td>If isolated or interconnected electrical systems suffer total</td>
<td>OE – Sch-1</td>
<td>1 hour 48 hour</td>
</tr>
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<td></td>
<td></td>
<td>electrical system collapse</td>
<td>OE – Sch-2</td>
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</table>

All DOE OE-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance.

All DOE OE-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance.

*All entities required to file a DOE OE-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.*
<table>
<thead>
<tr>
<th></th>
<th>Interconnected system separation or system islanding</th>
<th>Total system shutdown Partial shutdown, separation, or islanding</th>
<th>NERC Prelim Final report</th>
<th>24 hour 60 day</th>
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<tr>
<td>2</td>
<td>Loss of generation</td>
<td>≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection</td>
<td>NERC Prelim Final report</td>
<td>24 hour 60 day</td>
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<tr>
<td>3</td>
<td>Loss of firm load ≥15-minutes</td>
<td>Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand</td>
<td>NERC Prelim Final report</td>
<td>24 hour 60 day</td>
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<tr>
<td>4</td>
<td>Firm load shedding</td>
<td>≥100 MW to maintain continuity of bulk system</td>
<td>NERC Prelim Final report</td>
<td>24 hour 60 day</td>
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<td>5</td>
<td>System operation or operation actions resulting in:</td>
<td>• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS</td>
<td>NERC Prelim Final report</td>
<td>24 hour 60 day</td>
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<td>Reliability standard TOP-007.</td>
<td>NERC Prelim Final report</td>
<td>72 hour 60 day</td>
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<td>7</td>
<td>As requested by ORS Chairman</td>
<td>Due to nature of disturbance &amp; usefulness to industry (lessons learned)</td>
<td>NERC Prelim Final report</td>
<td>24 hour 60 day</td>
</tr>
</tbody>
</table>

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

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

1. **Title:** System Restoration Plans
2. **Number:** EOP-005-1
3. **Purpose:** To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system.
4. **Applicability**
   4.1. Transmission Operators.
   4.2. Balancing Authorities.
5. **Effective Date:** One year after BOT adoption.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.

R2. Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.

R3. Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.

R4. Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.

R5. Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.

R6. Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

R7. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.

R8. Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator’s area.

R9. The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.
R10. The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

R10.1. The Transmission Operator shall perform this simulation or testing at least once every five years.

R11. Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.

R11.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

R11.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

R11.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

R11.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

R11.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

R11.5.1. Voltage, frequency, and phase angle permit.

R11.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

R11.5.3. Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R11.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

M1. The Transmission Operator shall within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the blackstart units and Cranking Paths identified in the Transmission Operator’s restoration plan can perform their intended functions as required in the regional restoration plan.

M2. The Transmission Operator shall within 30 calendar days of a request from its Regional Reliability Organization, make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths for review at the Transmission Operator’s location.

D. Compliance

1. Compliance Monitoring Process
1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe
One calendar year.

1.3. Data Retention
The Transmission Operator must have its plan to reestablish its electric system available for review by the Regional Reliability Organization at all times.

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

1.4. Additional Compliance Information
Self-Certification: Each Transmission Operator shall annually self-certify to the Regional Reliability Organization that the following criteria have been met:

1.4.1 The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

1.4.2 A set of procedures for annual review for simulating and, where practical, actual testing and verification of the restoration plan resources and procedures.

1.4.3 Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

1.4.4 Any significant changes to the restoration plan must be reported to the Regional Reliability Organization.

1.4.5 The number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator’s area.

1.4.6 The Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started have been documented and this documentation is available for the Regional Reliability Organization’s review.

1.4.7 The blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

2. Levels of Non-Compliance

2.1. Level 1: Plan exists but is not reviewed annually.

2.2. Level 2: Plan exists but does not address one of the elements listed in Attachment 1–EOP-005.

2.3. Level 3: Did not make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths.

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

2.4.1 Plan exists but does not address two or more of the requirements in Attachment 1–EOP-005.

2.4.2 No restoration plan in place.
2.4.3 No simulation or test results as required in Requirement 10.

E. Regional Differences

None identified.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
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</table>
Attachment 1 – EOP-005

Elements for Consideration in Development of Restoration Plans

The Restoration Plan must consider the following requirements, as applicable:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.

2. The provision for a reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.

3. The plan must account for the possibility that restoration cannot be completed as expected.

4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.

5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures.

7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

8. The functions to be coordinated with and among Reliability Coordinators and neighboring Transmission Operators. (The plan should include references to coordination of actions among neighboring Transmission Operators and Reliability Coordinators when the plans are implemented.)

9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented.
A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-2
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to assure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**
   4.1. Transmission Operators.
   4.2. Generator Operators.
   4.3. Transmission Owners identified in the Transmission Operators restoration plan.

5. **Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System. The restoration plan shall include: \([\text{Violation Risk Factor} = \text{High}]\) \([\text{Time Horizon} = \text{Operations Planning}]\)

R1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator’s high level strategy for restoring the Interconnection.

R1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

R1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

R1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

R1.6. Identification of acceptable operating voltage and frequency limits during restoration.
R1.7. Operating Processes to reestablish connections within the Transmission Operator’s System for areas that have been restored and are prepared for reconnection.

R1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

R1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator’s criteria.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually agreed predetermined schedule. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R3.1. If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.

R4. Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R4.1. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: [Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]

R6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

R6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.
R6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]

R8. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]

R9. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include:

R9.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

R9.2. A list of required tests including:

R9.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

R9.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

R9.3. The minimum duration of each of the required tests.

R10. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R10.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

R10.2. Restoration priorities.

R10.3. Building of cranking paths.

R10.4. Synchronizing (re-energized sections of the System).
R11. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator’s restoration plan that are outside of their normal tasks. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R12. Each Transmission Operator shall participate in its Reliability Coordinator’s restoration drills, exercises, or simulations as requested by its Reliability Coordinator. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R13. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R14. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator’s restoration plan within 24 hours following such change. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R16. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

   R16.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R9.

   R16.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

R17. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

   R17.1. System restoration plan including coordination with the Transmission Operator.

   R17.2. The procedures documented in Requirement R14.
R18. Each Generator Operator shall participate in the Reliability Coordinator’s restoration drills, exercises, or simulations as requested by the Reliability Coordinator. [*Violation Risk Factor = Medium*] [*Time Horizon = Operations Planning*]

C. Measures

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.

M2. Each Transmission Operator shall have evidence such as e-mails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, e-mails with receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator’s restoration plan to its Reliability Coordinator in accordance with Requirement R3.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails with receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

M7. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.

M8. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.


M10. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R10.
M11. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R11.

M12. Each Transmission Operator shall have evidence, such as training records, that it participated in the Reliability Coordinator’s restoration drills, exercises, or simulations as requested in accordance with Requirement R12.

M13. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R13.

M14. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R14.

M15. Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within twenty-four hours of such changes in accordance with Requirement R15.

M16. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R16.

M17. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R17.

M18. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator’s restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R18.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

       Regional Entity.

   1.2. Compliance Monitoring Period and Reset Time Frame

       Not applicable.

   1.3. Compliance Monitoring and Enforcement Processes:

       Compliance Audits

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

1.4. Data Retention

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

- Approved restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.

- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.

- Submission of the Transmission Operator’s annually reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.

- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three years for Requirement R4, Measure M4.

- The current, restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.

- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.

- Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.

- Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.

- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R9, Measure M9.

- Actual training program materials or descriptions for three calendar years for Requirement R10, Measure M10.

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit.
as well as one previous compliance audit period for Requirement R12, Measure M12.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

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

- Actual training program materials or descriptions and actual training records for three calendar years for Requirement R11, Measure M11.

If a Transmission Operator, applicable Transmission owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in force since its last compliance audit for Requirement R13, Measure M13.

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

- Current documentation and any documentation in force since its last compliance audit on procedures to start each Blackstart Resources and for energizing a bus for Requirement R14, Measure M14.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R15, Measure M15.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R16, Measure M16.
- Actual training program materials and actual training records for three calendar years for Requirement R17, Measure M17.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R18, Measure M18.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

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

1.5. Additional Compliance Information

None.
## 2. Violation Severity Levels

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<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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<tbody>
<tr>
<td><strong>R1.</strong></td>
<td>The Transmission Operator has an approved plan but failed to comply with one of the sub-requirements within the requirement.</td>
<td>The Transmission Operator has an approved plan but failed to comply with two of the sub-requirements within the requirement.</td>
<td>The Transmission Operator has an approved plan but failed to comply with three of the sub-requirements within the requirement.</td>
<td>The Transmission Operator does not have an approved restoration plan.</td>
</tr>
<tr>
<td><strong>R2.</strong></td>
<td>The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR The Transmission Operator provided the information to all entities but was up to 30 calendar days late in doing so.</td>
<td>The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR The Transmission Operator provided the information to all entities but was more than 30 and less than or equal to 60 calendar days late in doing so.</td>
<td>The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR The Transmission Operator provided the information to all entities but was more than 60 and less than or equal to 90 calendar days late in doing so.</td>
<td>The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR The Transmission Operator provided the information to all entities but was more than 90 calendar days late in doing so.</td>
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<td><strong>R3.</strong></td>
<td>The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the pre-determined schedule.</td>
<td>The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the pre-determined schedule.</td>
<td>The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the pre-determined schedule.</td>
<td>The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the pre-determined schedule.</td>
</tr>
<tr>
<td><strong>R4.</strong></td>
<td>The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change.</td>
<td>The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within more than 90 calendar days but less than 120 calendar days of an unplanned change.</td>
<td>The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within more than 120 calendar days but less than 150 calendar days of an unplanned change.</td>
<td>The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within more than 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within more than 150 calendar days of an unplanned change.</td>
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### Standard EOP-005-2 — System Restoration from Blackstart Resources

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<td>to the Reliability Coordinator prior to a planned BES modification.</td>
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<td>R5.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its implementation date.</td>
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<td>R6.</td>
<td>The Transmission Operator performed the verification within the required timeframe but did not comply with one of the sub-requirements.</td>
<td>The Transmission Operator performed the verification within the required timeframe but did not comply with two of the sub-requirements.</td>
<td>The Transmission Operator performed the verification but did not complete it within the five calendar year period.</td>
<td>The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the sub-requirements.</td>
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<tr>
<td>R7.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator did not implement its restoration plan following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES. Or, if the restoration plan cannot be executed as expected, the Transmission Operator did not utilize its restoration plan strategies to facilitate restoration.</td>
</tr>
<tr>
<td>R8.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the established procedures of the Reliability Coordinator following a Disturbance in</td>
</tr>
<tr>
<td>R#</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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<tr>
<td>R9.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>which Blackstart Resources have been utilized in restoring the shut down area of the BES to service.</td>
</tr>
<tr>
<td>R10.</td>
<td>The Transmission Operator’s training does not address one of the sub-requirements of Requirement R10.</td>
<td>The Transmission Operator’s training does not address two of the sub-requirements of Requirement R10.</td>
<td>The Transmission Operator’s training does not address three or more of the sub-requirements of Requirement R10.</td>
<td>The Transmission Operator has not included System restoration training in its operations training program.</td>
</tr>
<tr>
<td>R11.</td>
<td>The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider did not train less than or equal to 10% of the personnel required by Requirement R11 within a two calendar year period.</td>
<td>The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R11 within a two calendar year period.</td>
<td>The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R11 within a two calendar year period.</td>
<td>The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider did not train more than 50% of the personnel required by Requirement R11 within a two calendar year period.</td>
</tr>
<tr>
<td>R12.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator has failed to comply with a request for their participation from the Reliability Coordinator.</td>
</tr>
<tr>
<td>R13.</td>
<td>N/A</td>
<td>The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually agreed upon procedures or protocols.</td>
<td>N/A</td>
<td>The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually agreed upon procedure or protocol.</td>
</tr>
<tr>
<td>R#</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
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</tr>
<tr>
<td>R14.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.</td>
</tr>
<tr>
<td>R15.</td>
<td>The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a change in Blackstart Resource capability affecting the ability to meet the Transmission Operator’s restoration plan within 24 hours but did make the notification within 48 hours.</td>
<td>The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a change in Blackstart Resource capability affecting the ability to meet the Transmission Operator’s restoration plan within 24 hours but did make the notification within 72 hours.</td>
<td>The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a change in Blackstart Resource capability affecting the ability to meet the Transmission Operator’s restoration plan within 24 hours but did make the notification within 96 hours.</td>
<td></td>
</tr>
<tr>
<td>R16.</td>
<td>The Generator Operator with a Blackstart Resource did not maintain testing records for one of the requirements for a Blackstart Resource. Or did not supply the Blackstart Resource testing records as requested within 59 calendar days of the request.</td>
<td>The Generator Operator with a Blackstart Resource did not maintain testing records for two of the requirements for a Blackstart Resource. Or did not supply the Blackstart Resource testing records as requested for 60 days to 89 calendar days after the request.</td>
<td>The Generator Operator with a Blackstart Resource did not maintain testing records for three of the requirements for a Blackstart Resource. Or did not supply the Blackstart Resource testing records as requested for 90 to 119 calendar days after the request.</td>
<td></td>
</tr>
<tr>
<td>R17.</td>
<td>The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R17 within a two calendar year period.</td>
<td>The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R17 within a two calendar year period.</td>
<td>The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R17 within a two calendar year period.</td>
<td></td>
</tr>
<tr>
<td>R18.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Generator Operator has failed to comply with a request for their participation from the Reliability Coordinator.</td>
</tr>
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E. Regional Variances

None.

Version History

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<th>Date</th>
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<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
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<tr>
<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
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<td>1</td>
<td>May 2, 2007</td>
<td>Approved by Board of Trustees</td>
<td>Revised</td>
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<tr>
<td>2</td>
<td>TBD</td>
<td>Revisions pursuant to Project 2006-03</td>
<td>Updated testing requirements</td>
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<td></td>
<td>Incorporated Attachment 1 into</td>
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<td>the requirements</td>
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<td>Updated Measures and Compliance</td>
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<td>to match new Requirements</td>
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<tr>
<td>2</td>
<td>August 5, 2009</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Reliability Coordination – System Restoration
2. Number: EOP-006-1
3. Purpose: The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. Applicability
   4.1. Reliability Coordinator.
5. Effective Date: January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.

R2. The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.

R3. The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.

R4. The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.

R5. Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.

R6. The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request a current copy of the restoration plan of each Transmission Operator in its Reliability Coordinator Area that will be used to confirm that it meets Requirement 1.

M2. The Reliability Coordinator 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 Reliability Coordinator monitored restoration progress and coordinated any needed assistance in accordance with Requirement 2.
M3. The Reliability Coordinator shall have and provide upon request a current copy of the Reliability Coordinator Area restoration plan that confirms that the Reliability Coordinator role of providing coordination between individual Transmission Operator restoration plans is included in the Reliability Coordinator Restoration Plan. (Requirement 3)

M4. The Reliability Coordinator 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 it served as the primary contact to disseminate information to neighboring Reliability Coordinators and Transmission Operators and Balancing Authorities that were not immediately involved in restoration. (Requirement 4)

M5. The Reliability Coordinator 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 it approved, communicated, and coordinated the re-synchronizing of major system islands or synchronizing points. (Requirement 5)

M6. The Reliability Coordinator shall have and provide upon request, evidence that could include, but is not limited to system restoration plan, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to determine if it took actions to restore normal operations, once an operating emergency was mitigated, in accordance with its restoration plan. (Requirement 6)

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 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 twelve months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator shall have the current version of its Transmission Operator’s restoration plans (Measure 1) and its current Reliability Coordinator Area restoration plan (Measure 3)

Each Reliability Coordinator shall keep historical data (evidence) gathered as a result of each major system disturbance requiring the implementation of system restoration plans and data gathered during the restoration period until normal system operation is resumed, for three years (Measure 2, 4, 5 and 6).

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:

2.1. Level 1: Did not have one of the Transmission Operator restoration plans within the Reliability Coordinator’s Area as specified in R1.

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 Does not have a Reliability Coordinator Restoration plan that defines the requirement of the Reliability Coordinator to provide coordination between individual Transmission Operator restoration plans as specified in R3.

2.3.2 No evidence it served as the primary contact to disseminate information to neighboring Reliability Coordinators, Transmission Operators and Balancing Authorities that were not immediately involved in restoration. (Requirement 4).

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 Did not have two or more of the Transmission Operator restoration plans within the Reliability Coordinator’s Area as specified in R1.
2.4.2 Did not monitor restoration progress and coordinate assistance as specified in R2.

2.4.3 Did not approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points as specified in R5.

2.4.4 Did not take action in accordance with its restoration plan to return to normal operations once an operating emergency was mitigated as specified in R6.

E. Regional Differences

None identified.

Version History

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<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: System Restoration Coordination
2. Number: EOP-006-2
3. Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. Applicability:
   4.1. Reliability Coordinators.
5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator’s restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator’s restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]

R1.1. A description of the high level strategy to be employed during restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator’s restoration plan.

R1.2. Operating Processes for restoring the Interconnection.

R1.3. Descriptions of the elements of coordination between individual Transmission Operator restoration plans.

R1.4. Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.

R1.5. Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

R1.7. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
R1.8. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

R1.9. Criteria for transferring operations and authority back to the Balancing Authority.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R4. Each Reliability Coordinator shall review their neighboring Reliability Coordinator’s restoration plans. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R4.1. If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R5.1. The Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator’s submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation date. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

R7. Each Reliability Coordinator shall work with its affected Generator Operators, and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]

R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability
Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]

R9. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R9.1. The coordination role of the Reliability Coordinator.

R9.2. Reestablishing the Interconnection.

R10. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R10.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators’ restoration plans to participate in a drill, exercise, or simulation at least every two calendar years.

C. Measures

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan in accordance with Requirement R1.

M2. Each Reliability Coordinator shall provide evidence such as e-mails with receipts, posting to a secure web site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets that it has reviewed its neighboring Reliability Coordinator’s restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.

M5. Each Reliability Coordinator shall provide evidence, such as a review signature sheet or emails, that it has reviewed, approved or disapproved, and notified its Transmission Operator’s within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

M6. Each Reliability Coordinator shall have documentation such as e-mail receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the implementation date in accordance with Requirement R6.
M7. Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.

M8. If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.

M9. Each Reliability Coordinator shall have an electronic or hard copy of its training records available showing that it has provided training in accordance with Requirement R9.

M10. Each Reliability Coordinator shall have evidence that it conducted two System restoration drills, exercises, or simulations per calendar year and that Transmission Operators and Generator Operators included in the Reliability Coordinator’s restoration plan were invited in accordance with Requirement R10.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority
       Regional Entity.

   1.2. Compliance Monitoring Period and Reset Time Frame
       Not applicable.

   1.3. Compliance Monitoring and Enforcement Processes:
       Compliance Audits
       Self-Certifications
       Spot Checking
       Compliance Violation Investigations
       Self-Reporting
       Complaints

   1.4. Data Retention
       The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
       - The current restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.
       - Distribution of its most recent restoration plan and any restoration plans in force for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
       - It’s reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
o Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.

o The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.

o The current, approved restoration plan and any restoration plans in force for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.

o If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R7, Measure M7.

o If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R8, Measure M8.

o Actual training program materials or descriptions for three calendar years for Requirements R9, Measure M9.

o Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit as well as one previous compliance audit period for Requirement R10, Measure M10.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.5. Additional Compliance Information

None.
2. **Violation Severity Levels**

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<th>R#</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
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<td><strong>R1.</strong></td>
<td>The Reliability Coordinator failed to include one sub-requirement of Requirement R1 within its restoration plan.</td>
<td>The Reliability Coordinator failed to include two sub-requirements of Requirement R1 within its restoration plan.</td>
<td>The Reliability Coordinator failed to include three of the sub-requirements of Requirement R1 within its restoration plan.</td>
<td>The Reliability Coordinator failed to include four or more of the sub-requirements within its restoration plan.</td>
</tr>
<tr>
<td><strong>R2.</strong></td>
<td>The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.</td>
<td>The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.</td>
<td>The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.</td>
<td>The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.</td>
</tr>
<tr>
<td><strong>R3.</strong></td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.</td>
</tr>
<tr>
<td><strong>R4.</strong></td>
<td>The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 60 calendar days.</td>
<td>The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 90 calendar days.</td>
<td>The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 120 calendar days.</td>
<td>The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 120 calendar days.</td>
</tr>
<tr>
<td>R5.</td>
<td>The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt. OR The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt. OR The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.</td>
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<tr>
<td>R6.</td>
<td>The Reliability Coordinator did not make its latest restoration plan and the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available to all of its System Operators in its primary and backup control rooms prior to the implementation date within 15 calendar days of the implementation date. The Reliability Coordinator did not make its latest restoration plan and the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available to all of its System Operators in its primary and backup control rooms prior to the implementation date within 20 calendar days of the implementation date. The Reliability Coordinator did not make its latest restoration plan and the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available to all of its System Operators in its primary and backup control rooms prior to the implementation date within 25 calendar days of the implementation date. The Reliability Coordinator did not make its latest restoration plan and the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available to all of its System Operators in its primary and backup control rooms for more than 25 calendar days after its implementation date. The Reliability Coordinator did not make its latest restoration plan and the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available to all of its System Operators in its primary and backup control rooms for more than 25 calendar days after its implementation date.</td>
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<td>R7.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators.</td>
</tr>
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Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.

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<tr>
<th>R8.</th>
<th>N/A</th>
<th>N/A</th>
<th>N/A</th>
<th>The Reliability Coordinator did not coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.</th>
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<tr>
<th>R9.</th>
<th>N/A</th>
<th></th>
<th>N/A</th>
<th>The Reliability Coordinator supplied annual System restoration training but did not address both of the sub-requirements. OR The Reliability Coordinator supplied the required System restoration training but it was over two calendar years from the last training offered.</th>
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<tr>
<th>R10.</th>
<th>The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.</th>
<th>The Reliability Coordinator did not invite a Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.</th>
<th>N/A</th>
<th>The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.</th>
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E. Regional Variances

None.

Version History

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<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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<td>2</td>
<td>TBD</td>
<td>Revisions pursuant to Project 2006-03</td>
<td>Updated Measures and Compliance to match new Requirements</td>
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<td>2</td>
<td>August 5, 2009</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Establish, Maintain, and Document a Regional Blackstart Capability Plan.
2. Number: EOP-007-0
3. Purpose: A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans (SRP).
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a system BCP, as part of an overall coordinated Regional SRP. The Regional SRP shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include:
   
   R1.1. A requirement to have a database that contains all blackstart generators\(^1\) designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method.

   R1.2. A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional SRP. This requirement can be met through either simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements.

   R1.3. Blackstart unit testing requirements including, but not limited to:
      
      R1.3.1. Testing frequency (minimum of one third of the units each year).

      R1.3.2. Type of test required, including the requirement to start when isolated from the system.

      R1.3.3. Minimum duration of tests.

   R1.4. A requirement to review and update the Regional BCP at least every five years.

R2. The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.

\(^1\) A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Regional Reliability Organization in accordance with the Regional Blackstart Capability plan or that unit will no longer be considered a blackstart unit.
C. Measures

M1. The Regional Reliability Organization’s BCP shall include all four of the requirements in Reliability Standard EOP-007-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided its BCP in accordance with Reliability Standard EOP-007-0_R2.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility
   
   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe
   
   Current Regional BCP: on request (30 calendar days).

   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: The Regional Reliability Organization’s Blackstart Capability Plan was incomplete in one of the four requirements defined above in Reliability Standard EOP-007-0_R1.

   2.3. Level 3: Not applicable.

   2.4. Level 4: The Regional Reliability Organization’s Blackstart Capability Plan was not provided (Reliability Standard EOP-007-0_R1), or was incomplete in two or more of the four requirements defined above in Reliability Standard EOP-007-0_R1.

E. Regional Differences

1. None.

Version History

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Adopted by NERC Board of Trustees: February 8, 2005
Effective Date: April 1, 2005
A. Introduction
1. Title: Plans for Loss of Control Center Functionality
2. Number: EOP-008-0
3. Purpose: Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. Applicability
   4.1. Transmission Operators.
   4.2. Balancing Authorities.
   4.3. Reliability Coordinators.
5. Effective Date: April 1, 2005

B. Requirements
R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:
   R1.1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
   R1.2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
   R1.3. The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
   R1.4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
   R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
   R1.6. The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
   R1.7. The plan shall be reviewed and updated annually.
   R1.8. Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures
M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance
1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. **Compliance Monitoring Period and Reset Timeframe**

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. **Data Retention**

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. **Additional Compliance Information**

Not specified.

2. **Levels of Non-Compliance**

2.1. **Level 1:** NA

2.2. **Level 2:** A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. **Level 3:** A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

2.4. **Level 4:** A contingency plan has not been developed, implemented, and tested.

E. **Regional Differences**

1. None identified.

Version History

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A. Introduction

1. **Title:** Documentation of Blackstart Generating Unit Test Results
2. **Number:** EOP-009-0
3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.
4. **Applicability:**
   - 4.1. Generator Operator
   - 4.2. Generator Owner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.

R2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

C. Measures

M1. The Generator Operator shall have evidence it provided the test results specified in Reliability Standard EOP-009-0R1 as specified in Reliability Standard EOP-009-0_R2.

D. Compliance

1. **Compliance Monitoring Process**
   1.1. **Compliance Monitoring Responsibility**
   Compliance Monitor: Regional Reliability Organization.
   1.2. **Compliance Monitoring Period and Reset Timeframe**
   Current test results: to the Regional Reliability Organization and upon request to NERC (30 calendar days).
   1.3. **Data Retention**
   None specified.
   1.4. **Additional Compliance Information**
   None
2. **Levels of Non-Compliance**
   2.1. **Level 1:** Startup and operation testing of each blackstart generating unit was performed, but the documentation was incomplete.
   2.2. **Level 2:** Not applicable.
2.3. **Level 3:** Startup and operation testing of a blackstart generating unit was only partially performed.

2.4. **Level 4:** Startup and operation testing of each blackstart generating unit was not performed.

E. **Regional Differences**

1. None identified.

**Version History**

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A. Introduction
1. Title: Facility Connection Requirements
2. Number: FAC-001-0
3. Purpose: To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.
4. Applicability:
   4.1. Transmission Owner
5. Effective Date: April 1, 2005

B. Requirements
R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner’s facility connection requirements shall address connection requirements for:
   R1.1. Generation facilities,
   R1.2. Transmission facilities, and
   R1.3. End-user facilities

R2. The Transmission Owner’s facility connection requirements shall address, but are not limited to, the following items:
   R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
      R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.
      R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.
      R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.
      R2.1.4. Breaker duty and surge protection.
      R2.1.5. System protection and coordination.
      R2.1.6. Metering and telecommunications.
      R2.1.7. Grounding and safety issues.
      R2.1.8. Insulation and insulation coordination.
      R2.1.9. Voltage, Reactive Power, and power factor control.
      R2.1.10. Power quality impacts.
      R2.1.11. Equipment Ratings.
      R2.1.12. Synchronizing of facilities.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1.

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0_R2.

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
   Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe
   On request (five business days).

1.3. Data Retention
   None specified.

1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.
2.4. **Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. **Regional Differences**

1. None identified.

**Version History**

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A. Introduction

1. Title: Coordination of Plans For New Generation, Transmission, and End-User Facilities
2. Number: FAC-002-0
3. Purpose: To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.
4. Applicability:
   - Generator Owner
   - Transmission Owner
   - Distribution Provider
   - Load-Serving Entity
   - Transmission Planner
   - Planning Authority
5. Effective Date: April 1, 2005

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:
   - Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.
   - Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.
   - Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.
   - Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.
   - Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).
C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider’s documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: RRO.

1.2. Compliance Monitoring Period and Reset Timeframe
On request (within 30 calendar days).

1.3. Data Retention
Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.4. Additional Compliance Information
None

2. Levels of Non-Compliance

2.1. Level 1: Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Assessments of the impacts of new facilities were not provided.

E. Regional Differences

1. None identified.

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Adopted by NERC Board of Trustees: February 8, 2005
Effective Date: April 1, 2005
A. Introduction

1. Title: Transmission Vegetation Management Program
2. Number: FAC-003-1
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. Applicability:
   4.1. Transmission Owner.
   4.2. Regional Reliability Organization.
   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5. Effective Dates:
   5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.
   5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner’s objectives, practices, approved procedures, and work specifications.

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner’s transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

1 ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.
vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.
R3. The Transmission Owner shall report quarterly to its RRO, or the RRO’s designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner’s, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner’s TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner’s standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.
M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO’s designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO
NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.
2.3. **Level 3:**

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. **Level 4:**

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. **Regional Differences**

None Identified.

**Version History**

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</table>
2. Changed “60” to “Sixty” in section A, 5.2.  
3. Added “Proposed Effective Date: April 7, 2006” to footer.  
4. Added “Draft 3: November 17, 2005” to footer. | 01/20/06 |
A. Introduction

1. Title: Facility Ratings Methodology
2. Number: FAC-008-1
3. Purpose: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. Applicability
   4.1. Transmission Owner
   4.2. Generator Owner
5. Effective Date: August 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:

   R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

   R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

      R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

      R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

   R1.3. Consideration of the following:

      R1.3.1. Ratings provided by equipment manufacturers.

      R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer’s warranty, IEEE, ANSI or other standards).

      R1.3.3. Ambient conditions.

      R1.3.4. Operating limitations.

      R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the
Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

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

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.
The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. **Additional Compliance Information**

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings methodology, and the associated responses

2. **Levels of Non-Compliance**

2.1. **Level 1:** There shall be a level one non-compliance if any of the following conditions exists:

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator’s, Transmission Operator, Transmission Planner, or Planning Authority’s comments on the Facility Ratings Methodology.

2.2. **Level 2:** The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. **Level 3:** The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. **Level 4:** The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. **Regional Differences**

None Identified.

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<td>Frame” and “twelve” to “12” in item D, 1.2.</td>
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A. Introduction

1. Title: Establish and Communicate Facility Ratings
2. Number: FAC-009-1
3. Purpose: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. Applicability
   4.1. Transmission Owner
   4.2. Generator Owner
5. Effective Date: October 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.

R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.
   M1.1 The Transmission Owner’s and Generator Owner’s Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.

M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

       Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Time Frame

       Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

       The Performance-Reset Period shall be twelve months from the last finding of non-compliance.
1.3. **Data Retention**

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

1.4. **Additional Compliance Information**

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology
1.4.2 Facility Ratings
1.4.3 Evidence that Facility Ratings were distributed
1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. **Levels of Non-Compliance**

2.1. **Level 1:** Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.2. **Level 2:** Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.3. **Level 3:** Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.

2.4. **Level 4:** No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

E. **Regional Differences**

None Identified.

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A. Introduction

1. Title: System Operating Limits Methodology for the Planning Horizon
2. Number: FAC-010-2.1
3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Planning Authority

5. Effective Date: April 19, 2010

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system’s response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

1 The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.
R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system’s response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or 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.

R3. The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tc.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures
M1. The Planning Authority’s SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

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

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

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

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
2.1.2 No evidence of responses to a recipient’s comments on the SOL Methodology.

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

   2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

   2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

   2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.
### 3. Violation Severity Levels:

<table>
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<th>Lower</th>
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<tr>
<td>R1</td>
<td>Not applicable.</td>
<td>The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2</td>
<td>The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.</td>
<td>The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.</td>
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<td>R2</td>
<td>The Planning Authority’s SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)</td>
<td>The Planning Authority’s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)</td>
<td>The Planning Authority’s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2–R2.4)</td>
<td>The Planning Authority’s SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2–R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5–R2.6)</td>
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<td>R3</td>
<td>The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.</td>
<td>The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.</td>
<td>The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.</td>
<td>The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.</td>
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<td>R4</td>
<td>One or both of the following: The Planning Authority issued its SOL Methodology and changes</td>
<td>One of the following: The Planning Authority issued its SOL Methodology and changes</td>
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<td>One of the following: The Planning Authority failed to issue its SOL Methodology and changes</td>
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<td>to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</td>
<td>to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</td>
<td>to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</td>
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<tr>
<td>R5</td>
<td>The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</td>
<td>The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</td>
<td>The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</td>
<td>The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</td>
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E. **Regional Differences**

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

   1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

      1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

      1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

      1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

      1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

      1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

      1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

      1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

   1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

   1.2.2 Cascading does not occur.

   1.2.3 Uncontrolled separation of the system does not occur.

   1.2.4 The system demonstrates transient, dynamic and voltage stability.

   1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

   1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.
1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

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<td>January 22, 2010</td>
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<td>2.1</td>
<td>November 5, 2009</td>
<td>Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.</td>
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A. Introduction

1. Title: System Operating Limits Methodology for the Operations Horizon
2. Number: FAC-011-2
3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. Applicability
   4.1. Reliability Coordinator
5. Effective Date: April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
   R1.1. Be applicable for developing SOLs used in the operations horizon.
   R1.2. State that SOLs shall not exceed associated Facility Ratings.
   R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
   R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
   R2.2. Following the single Contingencies1 identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
      R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
      R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
      R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
   R2.3. In determining the system’s response to a single Contingency, the following shall be acceptable:
      R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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1 The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.
R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies.

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL TV.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures
M1. The Reliability Coordinator’s SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

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

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)
2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient’s comments on the SOL Methodology

2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.
### 3. Violation Severity Levels:

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<td>R1</td>
<td>Not applicable.</td>
<td>The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2</td>
<td>The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.</td>
<td>The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.</td>
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<td>R2</td>
<td>The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)</td>
<td>Not applicable.</td>
<td>The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)</td>
<td>The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)</td>
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<td>R3</td>
<td>The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.</td>
<td>The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.</td>
<td>The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.</td>
<td>The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through R3.7.</td>
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<td>R4</td>
<td>One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was</td>
<td>One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30</td>
<td>One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60</td>
<td>One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and</td>
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<td>provided up to 30 calendar days after the effectiveness of the change.</td>
<td>calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</td>
<td>calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</td>
<td>changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</td>
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Adopted by Board of Trustees: June 24, 2008
Effective Date: April 29, 2009
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<td>R5</td>
<td>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</td>
<td>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</td>
<td>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. <strong>OR</strong> The Reliability Coordinator’s response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</td>
<td>30 calendar days after the effectiveness of the change. <strong>OR</strong> The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. <strong>OR</strong> The Reliability Coordinator’s response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</td>
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Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

   1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

      1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

      1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

      1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

      1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

      1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

      1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

      1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

   1.2. SOLs shall be established such that for multiple Facility Contingencies in 1.1.1 through 1.1.5 operation within the SOL shall provide system performance consistent with the following:

      1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

      1.2.2 Cascading does not occur.

      1.2.3 Uncontrolled separation of the system does not occur.

      1.2.4 The system demonstrates transient, dynamic and voltage stability.

      1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

      1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.
1.2.7  To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3.  SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1  Cascading does not occur.

1.4.  The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

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A. Introduction

1. Title: Transfer Capability Methodology
2. Number: FAC-012-1
3. Purpose: To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. Effective Date: August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).

R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.

R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:

R1.3.1. Transmission system topology

R1.3.2. System demand

R1.3.3. Generation dispatch

R1.3.4. Current and projected transmission uses

R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.

R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.

R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R3.1. Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.

R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.
R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.

R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator’s methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.

M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.

M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.

M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

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

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.
1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

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

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.1.2 No evidence of responses to a recipient’s comments on the Transfer Capability Methodology.

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. Regional Differences

None identified.

Version History

<table>
<thead>
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<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
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<td>1</td>
<td>08/01/05</td>
<td>1. Lower cased the word “draft” and “drafting team” where appropriate.</td>
<td>01/20/06</td>
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<tr>
<td></td>
<td></td>
<td>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—)”</td>
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<tr>
<td></td>
<td></td>
<td>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</td>
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</tbody>
</table>
A. Introduction
1. Title: Establish and Communicate Transfer Capabilities
2. Number: FAC-013-1
3. Purpose: To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. Applicability
   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
5. Effective Date: October 7, 2006

B. Requirements
R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.
R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:
   R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.
   R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures
M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.
M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance
1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization
   1.2. Compliance Monitoring Period and Reset Timeframe
   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance
Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

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

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

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<th>Version</th>
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<th>Action</th>
<th>Change Tracking</th>
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<td>3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.”</td>
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<tr>
<td></td>
<td></td>
<td>4. Added or removed “periods.”</td>
<td></td>
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</table>
A. Introduction

1. Title: Establish and Communicate System Operating Limits
2. Number: FAC-014-2
3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability
   4.1. Reliability Coordinator
   4.2. Planning Authority
   4.3. Transmission Planner
   4.4. Transmission Operator

5. Effective Date: April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority’s SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated \( T_v \).

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).
R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

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

1.3. Data Retention
The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs
### 2. Violation Severity Levels:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1</strong></td>
<td>There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1)</td>
<td>There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1)</td>
<td>There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1)</td>
<td>There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1)</td>
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<tr>
<td><strong>R2</strong></td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2)</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2)</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2)</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2)</td>
</tr>
<tr>
<td><strong>R3</strong></td>
<td>There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R3)</td>
<td>There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R3)</td>
<td>There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R3)</td>
<td>There are SOLs for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R3)</td>
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<td><strong>R4</strong></td>
<td>The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)</td>
<td>The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)</td>
<td>The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)</td>
<td>The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R4)</td>
</tr>
<tr>
<td><strong>R5</strong></td>
<td>The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15</td>
<td>One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided.</td>
<td>One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided.</td>
<td>One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45</td>
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<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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<td>-------------</td>
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<tr>
<td>calendar days. (R5)</td>
<td>(R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5) Or The supporting information provided with the IROLs does not address 5.1.4</td>
<td>(R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5) Or The supporting information provided with the IROLs does not address 5.1.3</td>
<td>calendar days of the associated schedules. (R5) Or The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.</td>
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<tr>
<td>R6 The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2</td>
<td>Not applicable.</td>
<td>The Planning Authority identified the subset of multiple contingencies which result in stability limits but did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)</td>
<td>The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) Or The Planning Authority identified the subset of multiple contingencies which result in stability limits but did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)</td>
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E. Regional Differences

None identified.

Version History

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<th>Date</th>
<th>Action</th>
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<tr>
<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>New</td>
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<td>2</td>
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<td>Changed the effective date to January 1, 2009</td>
<td>Revised</td>
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<tr>
<td></td>
<td></td>
<td>Replaced Levels of Non-compliance with Violation Severity Levels</td>
<td></td>
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<tr>
<td>2</td>
<td>June 24, 2008</td>
<td>Adopted by Board of Trustees: FERC Order</td>
<td>Revised</td>
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<tr>
<td>2</td>
<td>January 22, 2010</td>
<td>Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order</td>
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

<table>
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<th>Completed Actions</th>
<th>Completion Date</th>
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<tbody>
<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 4, 2007</td>
</tr>
<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 1, 2007</td>
</tr>
<tr>
<td>3. Post second Draft Standard for industry comments</td>
<td>November 9, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 7, 2008</td>
</tr>
<tr>
<td>5. Post Draft Standard for Operating Committee approval</td>
<td>January 17, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
</tr>
</tbody>
</table>

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for PRC-STD-005-1. In response to comments, the drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system. FAC-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-005-1 was approved as a NERC reliability standard. This posting of the standard is for WECC Board of Director ballot. The Operating Committee recommends that the WECC Board of Directors approve the FAC-501-WECC-1 as a permanent replacement standard for PRC-STD-005-1 and that the Board of Directors submit the standard to the NERC and FERC for approval.

Justification for a Regional Standard

The NERC standard PRC-005-1 has requirements for equipment maintenance and inspection of relay and backup power systems. FAC-003-1 has requirements for vegetation management. The NERC standards do not have any maintenance and test requirements for the additional components such as breakers, reactive devices, transformers and the associated transmission line. The 40 major paths listed in the Attachment 1-FAC-501-WECC-1 are significant components for reliable delivery of power in the Western Interconnection. Breaker, transformer, and insulator failures cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers.
WECC Standard FAC-501-WECC-1 – Transmission Maintenance

The entities of the Western Interconnection through study and operation see optimizing the capacity for these paths as critical to the reliability of the Western Interconnection. The lack of redundant transmission in these corridors raises the level of scrutiny for the components and facilities associated with these paths; therefore, this standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.

Future Development Plan:

<table>
<thead>
<tr>
<th>Anticipated Actions</th>
<th>Anticipated Date</th>
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<tr>
<td>2. WECC Board ballots proposed standard</td>
<td>April 16-18, 2008</td>
</tr>
<tr>
<td>3. Drafting Team to review and respond to NERC industry comments</td>
<td>May 2008</td>
</tr>
<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
</tr>
<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
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</table>
This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.
A. Introduction

1. Title: Transmission Maintenance

2. Number: FAC-501-WECC-1

3. Purpose: To ensure the Transmission Owner of a transmission path identified in the table titled “Major WECC Transfer Paths in the Bulk Electric System” including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

4. Applicability


5. Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R.1. Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled “Major WECC Transfer Paths in the Bulk Electric System.”  [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

R1.1. Transmission Owners shall annually review their TMIP and update as required. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

R.2. Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP. [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

R.3. Transmission Owners shall implement and follow their TMIP. [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

C. Measures

M1. Transmission Owners shall have a documented TMIP per R.1.

M1.1 Transmission Owners shall have evidence they have annually reviewed their TMIP and updated as needed.

M2. Transmission Owners shall have evidence that their TMIP addresses the required maintenance details of R.2.
M3. Transmission Owners shall have records that they implemented and followed their TMIP as required in R.3. The records shall include:

1. The person or crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

   1.1 Compliance Monitoring Responsibility

       Compliance Enforcement Authority

   1.2 Compliance Monitoring Period

       The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:
       - Self-certification conducted annually
       - Spot check audits conducted anytime with 30 days notice given to prepare
       - Periodic audit as scheduled by the Compliance Enforcement Authority
       - Investigations
       - Other methods as provided for in the Compliance Monitoring Enforcement Program

       The Reset Time Frame shall be one year.

   1.3 Data Retention

       The Transmission Owners shall keep evidence for Measure M1 through M3 for three years plus the current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

       No additional compliance information.

2. Violation Severity Levels

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

       2.1.1 The TMIP does not include associated Facilities for one of the Paths
2.1.2 Transmission Owners did not review their TMIP annually as required by R.1.1.

2.1.3 The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.1.4 Transmission Owners and Transmission Operators do not have maintenance and inspection records as required by R.3 but have evidence that they are implementing and following their TMIP.

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

2.2.1 The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.2.2 The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.2.3 Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.3. High: There shall be a High Level of non-compliance if any of the following condition exists:

2.3.1 The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.3.2 The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.3.3 Transmission Owners are not performing maintenance and inspection for two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.
WECC Standard FAC-501-WECC-1 – Transmission Maintenance

2.4. Severe: There shall be a Severe Level of non-compliance if any of the following condition exists:

2.4.1 The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.4.2 The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.4.3 Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
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<th>Version</th>
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<th>Action</th>
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<tr>
<td>1</td>
<td>January 1, 2008</td>
<td>Permanent Replacement Standard for PRC-STD-005-1</td>
<td></td>
</tr>
</tbody>
</table>
Attachment 1-FAC-501-WECC-1
Transmission Line and Station Maintenance Details

The maintenance practices in the TMIP may be performance-based, time-based, conditional based, or a combination of all three. The TMIP shall include:

1. A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System;”

2. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition based trigger;

3. Transmission Line Maintenance Details:
   a. Patrol/Inspection
   b. Contamination Control
   c. Tower and wood pole structure management

4. Station Maintenance Details:
   a. Inspections
   b. Contamination Control
   c. Equipment Maintenance for the following:
      • Circuit Breakers
      • Power Transformers (including phase-shifting transformers)
      • Regulators
      • Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)
### Major WECC Transfer Paths in the Bulk Electric System
(Revised September 1, 2007)

<table>
<thead>
<tr>
<th>PATH NAME*</th>
<th>Path Number</th>
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<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>1</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>3</td>
</tr>
<tr>
<td>3. West of Cascades – North</td>
<td>4</td>
</tr>
<tr>
<td>4. West of Cascades – South</td>
<td>5</td>
</tr>
<tr>
<td>5. West of Hatwai</td>
<td>6</td>
</tr>
<tr>
<td>6. Montana to Northwest</td>
<td>8</td>
</tr>
<tr>
<td>7. Idaho to Northwest</td>
<td>14</td>
</tr>
<tr>
<td>8. South of Los Banos or Midway- Los Banos</td>
<td>15</td>
</tr>
<tr>
<td>9. Idaho – Sierra</td>
<td>16</td>
</tr>
<tr>
<td>10. Borah West</td>
<td>17</td>
</tr>
<tr>
<td>11. Idaho – Montana</td>
<td>18</td>
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<tr>
<td>12. Bridger West</td>
<td>19</td>
</tr>
<tr>
<td>13. Path C</td>
<td>20</td>
</tr>
<tr>
<td>14. Southwest of Four Corners</td>
<td>22</td>
</tr>
<tr>
<td>15. PG&amp;E – SPP</td>
<td>24</td>
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<tr>
<td>16. Northern – Southern California</td>
<td>26</td>
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<tr>
<td>17. Intmntn. Power Project DC Line</td>
<td>27</td>
</tr>
<tr>
<td>18. TOT 1A</td>
<td>30</td>
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<tr>
<td>19. TOT 2A</td>
<td>31</td>
</tr>
<tr>
<td>20. Pavant – Gonder 230 kV Intermountain – Gonder 230 kV</td>
<td>32</td>
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<tr>
<td>21. TOT 2B</td>
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<td>25. SDGE – CFE</td>
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<td>26. West of Colorado River (WOR)</td>
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</tr>
<tr>
<td>27. Southern New Mexico (NM1)</td>
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<tr>
<td>28. Northern New Mexico (NM2)</td>
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<tr>
<td>29. East of the Colorado River (EOR)</td>
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<tr>
<td>30. Cholla – Pinnacle Peak</td>
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<tr>
<td>31. Southern Navajo</td>
<td>51</td>
</tr>
<tr>
<td>32. Brownlee East</td>
<td>55</td>
</tr>
<tr>
<td>33. Lugo – Victorville 500 kV</td>
<td>61</td>
</tr>
<tr>
<td>34. Pacific DC Intertie</td>
<td>65</td>
</tr>
<tr>
<td>35. COI</td>
<td>66</td>
</tr>
<tr>
<td>36. North of John Day cutplane</td>
<td>73</td>
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<td>37. Alturas</td>
<td>76</td>
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<td>38. Montana Southeast</td>
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<tr>
<td>39. SCIT**</td>
<td></td>
</tr>
<tr>
<td>40. COI/PDCI – North of John Day cutplane**</td>
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</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
A. Introduction

1. Title: Interchange Information
2. Number: INT-001-3
3. Purpose:
   To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. Applicability:
   4.1. Purchase-Selling Entities.
   4.2. Balancing Authorities.
5. Effective Date: August 27, 2008 (U.S.)
   NERC Board Approval: October 9, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:
   R1.1. All Dynamic Schedules at the expected average MW profile for each hour.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:
   R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.
   R2.2. For each bilateral Inadvertent Interchange payback.

C. Measures

M1. The Purchasing-Selling Entity that serves the load shall have and provide upon request evidence that could include but is not limited to, its Interchange Transaction tags operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to confirm that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour as specified in Requirement 1.
M2. Each Sink Balancing Authority shall have and provide upon request evidence that could include but is not limited to, Interchange Transaction tags operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that Arranged Interchange was submitted to the Interchange Authority as specified in Requirements 2.1 and 2.2.

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 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

The Purchasing-Selling Entity that serves load and Sink Balancing Authority shall each 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

None.

2. Levels of Non-Compliance for Sink Balancing Authorities:

2.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and R2.2.

2.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

3. Levels of Non-Compliance for Purchasing-Selling Entities that Serve Load:

3.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R1.
3.2. **Level 2:** Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.3. **Level 3:** Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.4. **Level 4:** Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

E. **Regional Differences**


### Version History

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<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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<td>Adopted by Board of Trustees (Remove WECC Waiver)</td>
<td>Revised</td>
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<td>3</td>
<td>July 21, 2008</td>
<td>Regulatory Approval</td>
<td>Revised</td>
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</table>
A. Introduction

1. Title: Interchange Transaction Implementation

2. Number: INT-003-2

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

4. Applicability


5. Effective Date: January 1, 2007

B. Requirements

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

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

   R1.1.1. Interchange Schedule start and end time.

   R1.1.2. Energy profile.

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

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule’s start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority’s ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

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 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 Balancing Authority 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
None.

2. Levels of Non-Compliance for Balancing Authorities:
2.1. Level 1: There shall be a separate Level 1 non-compliance, if either of the following conditions exists:
   2.1.1 One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
   2.1.2 One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
2.2. **Level 2:** There shall be a separate Level 2 non-compliance, if either of the following conditions exists:

2.2.1 Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.2.2 Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.3. **Level 3:** There shall be a separate Level 3 non-compliance, if either of the following conditions exists:

2.3.1 Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.3.2 Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, if either of the following conditions exists:

2.4.1 Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1, and R1.1.2.

2.4.2 Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2.

**E. Regional Differences**

1. [MISO Scheduling Agent Waiver](#) dated November 21, 2002.


**Version History**

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<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Dynamic Interchange Transaction Modifications
2. Number: INT-004-2
3. Purpose: To ensure Dynamic Transfers are adequately tagged to be able to
determine their reliability impacts.
4. Applicability
   4.1. Balancing Authorities
   4.2. Reliability Coordinators
   4.3. Transmission Operators
   4.4. Purchasing-Selling Entities
5. Effective Date: August 27, 2008 (U.S.)
   NERC Board Approval: October 9, 2007

B. Requirements

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

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule
shall ensure the tag is updated for the next available scheduling hour and future hours
when any one of the following occurs:
   R2.1. The average energy profile in an hour is greater than 250 MW and in that hour
   the actual hourly integrated energy deviates from the hourly average energy
   profile indicated on the tag by more than ±10%.
   R2.2. The average energy profile in an hour is less than or equal to 250 MW and in
   that hour the actual hourly integrated energy deviates from the hourly average
   energy profile indicated on the tag by more than ±25 megawatt-hours.
   R2.3. A Reliability Coordinator or Transmission Operator determines the deviation,
   regardless of magnitude, to be a reliability concern and notifies the Purchasing-
   Selling Entity of that determination and the reasons.

C. Measures

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

D. Compliance

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

1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.

1.2. **Compliance Monitoring Period and Reset Time Frame**

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

1.3. **Data Retention**

Three months.

1.4. **Additional Compliance Information**

Not specified.

2. **Levels of Non-Compliance**

2.1. **Level 1:** Not specified.

2.2. **Level 2:** Not specified.

2.3. **Level 3:** Not specified.

2.4. **Level 4:** Not specified.

E. **Regional Differences**

1. None

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A. Introduction

1. Title: Interchange Authority Distributes Arranged Interchange
2. Number: INT-005-2
3. Purpose: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.
4. Applicability:
   4.1. Interchange Authority.
5. Effective Date: August 27, 2008. (U.S.)
   NERC Board Approval: May 2, 2007

B. Requirements

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

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

C. Measures

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

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization.
   1.2. Compliance Monitoring Period and Reset Time Frame
       The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.
   1.3. Data Retention
       The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.
   1.4. Additional Compliance Information
       Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.
Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.
1.4.2 Verified by spot checks in years between audits.
1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.
1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

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

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

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

2. Levels of Non-Compliance

2.1. Level 1: One occurrence\(^1\) of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences\(^1\) of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences\(^1\) of not distributing information to all involved reliability entities as described in R1.

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

E. Regional Differences

None

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\(^1\) This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.
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## Timing Table

### Interchange Timeline with Minimum Reliability-Related Response Times

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<td><strong>If Actual Arranged Interchange (RFI) is Submitted</strong></td>
<td><strong>Minimum Total Reliability Period</strong> (Columns A through D)</td>
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<tr>
<td><strong>≤1 hour prior to ramp start</strong></td>
<td><strong>≤ 1 minute from RFI submission</strong></td>
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<tr>
<td><strong>≤20 minutes prior to ramp start</strong></td>
<td><strong>≤ 1 minute from RFI submission</strong></td>
</tr>
<tr>
<td><strong>&gt;20 minutes to ≤1 hour prior to ramp start</strong></td>
<td><strong>≤ 1 minute from RFI submission</strong></td>
</tr>
<tr>
<td><strong>&gt;1 hour to &lt;4 hours prior to ramp start</strong></td>
<td><strong>≤ 1 minute from RFI submission</strong></td>
</tr>
<tr>
<td><strong>≥ 4 hours prior to ramp start</strong></td>
<td><strong>≤ 1 minute from RFI submission</strong></td>
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A. Introduction

1. Title: Interchange Authority Distributes Arranged Interchange
2. Number: INT-005-3
3. Purpose: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

4. Applicability:
4.1. Interchange Authority.

5. Effective Date: July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

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

C. Measures

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame
The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

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

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

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.
1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

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

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

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

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

2. Levels of Non-Compliance

2.1. **Level 1:** One occurrence\(^1\) of not distributing information to all involved reliability entities as described in R1.

2.2. **Level 2:** Two occurrences\(^1\) of not distributing information to all involved reliability entities as described in R1.

2.3. **Level 3:** Three occurrences\(^1\) of not distributing information to all involved reliability entities as described in R1.

2.4. **Level 4:** Four or more occurrences\(^1\) of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

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\(^1\) This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.
### Timing Requirements for all Interconnections except WECC

#### Interchange Timeline with Minimum Reliability-Related Response Times

<table>
<thead>
<tr>
<th>Request for Interchange Submitted</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>If Arranged Interchange (RFI)^2</strong> is Submitted</td>
<td>IA Assigned Time Classification</td>
<td>IA Makes Initial Distribution of Arranged Interchange</td>
<td>BA and TSP Conduct Reliability Assessments</td>
<td>IA Compiles and Distributes Status</td>
</tr>
<tr>
<td>&gt;1 hour after the RFI start time</td>
<td>ATF</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 2 hours to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;15 minutes prior to ramp start and ≤1 hour after the RFI start time</td>
<td>Late</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 10 minutes to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;1 hour and ≥ 15 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥1 hour to &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
</tbody>
</table>

---

2 Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
Example of Timing Requirements for all Interconnections except WECC

<table>
<thead>
<tr>
<th>Time Classification</th>
<th>RFI submit time relative to start time</th>
<th>Assessment</th>
<th>Time</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>On Time</td>
<td></td>
<td>2 hours</td>
<td>10 minutes</td>
<td>On Time</td>
</tr>
<tr>
<td>Late</td>
<td></td>
<td>20 minutes</td>
<td>15 minutes</td>
<td>Late</td>
</tr>
<tr>
<td>ATF</td>
<td></td>
<td>2 hours</td>
<td>1 hour</td>
<td>ATF</td>
</tr>
</tbody>
</table>

Ramp Start Time:
- 9:00
- 10:00

Interchange Start Time:
- 9:55
- 10:00
### Timing Requirements for WECC

<table>
<thead>
<tr>
<th>IA Assigned Time Classification</th>
<th>IA Makes Initial Distribution of Arranged Interchange</th>
<th>BA and TSP Conduct Reliability Assessments</th>
<th>IA Compiles and Distributes Status</th>
<th>BA Prepares Confirmed Interchange for Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>If Arranged Interchange (RFI)(^3) is Submitted</strong></td>
<td><strong>A</strong></td>
<td><strong>B</strong></td>
<td><strong>C</strong></td>
<td><strong>D</strong></td>
</tr>
<tr>
<td>&gt;1 hour after the start time</td>
<td>ATF</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 2 hours to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;10 minutes prior to ramp start and ≤ 1 hour after the start time</td>
<td>Late</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 10 minutes to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>10 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 5 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>11 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 6 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>12 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 7 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>13 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 8 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>14 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 9 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;1 hour and &gt; 15 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥ 1 hour and &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>Submitted before 10:00 PPT with start time &gt; 00:00 PPT of following day</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>By 12:00 PPT of day the Arranged Interchange was received by the IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
</tbody>
</table>

---

\(^3\) Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
Example of Timing Requirements for WECC

- **Time Classification**
  - **RFI submit time relative to start time**
    - 5:50: 4 hours before ramp start
    - 8:50: 1 hour before ramp start
  - **Assessment**
    - 2 hours
    - 20 minutes
    - 10 minutes

- **On Time**
  - 9:35

- **Late**
  - 9:50
  - 10:00
  - 11:00

- **ATF**
  - 5:50
  - 20 minutes
  - 10 minutes
  - 2 hours

*If submitted before 10:00 PPT with start time >= 00:00 PPT of the following day then assessment is >= 2 hours and by 12:00 PPT*
A. Introduction

1. Title: Response to Interchange Authority
2. Number: INT-006-2
3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. Applicability:
   4.1. Balancing Authority.
   4.2. Transmission Service Provider.
5. Effective Date: August 27, 2008. (U.S.)
   NERC Board Approved: May 2, 2007

B. Requirements

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

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

   R1.1.1. Energy profile (ability to support the magnitude of the Interchange).
   R1.1.2. Ramp (ability of generation maneuverability to accommodate).
   R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

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

C. Measures

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

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame
   The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

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

1.4. Additional Compliance Information

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

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

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

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

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

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

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

2. Levels of Non-Compliance

2.1. Level 1: One occurrence\(^1\) of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences\(^1\) of not responding to the Interchange Authority as described in R1.

\(^1\) This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.
2.3. **Level 3:** Three occurrences\(^1\) of not responding to the Interchange Authority as described in R1.

2.4. **Level 4:** Four or more occurrences\(^1\) of not responding to the Interchange Authority as described in R1 or no evidence provided.

E. **Regional Differences**

None.

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<td>Approved by FERC</td>
<td>Revised</td>
</tr>
</tbody>
</table>
### Timing Table

**Interchange Timeline with Minimum Reliability-Related Response Times**

<table>
<thead>
<tr>
<th>Request for Interchange Submitted</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>Minimum Total Reliability Period (Columns A through D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>≤1 hour prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
<td>15 minutes</td>
</tr>
<tr>
<td>&lt;20 minutes prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 5 minutes from Arranged Interchange receipt from IA for WECC</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
<td>10 minutes</td>
</tr>
<tr>
<td>&gt;20 minutes to ≤1 hour prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA for WECC</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
<td>15 minutes</td>
</tr>
<tr>
<td>&gt;1 hour to &lt; 4 hours prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 39 minutes prior to ramp start</td>
<td>1 hour plus 1 minute</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 1 hour 58 minutes prior to ramp start</td>
<td>4 hours</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Response to Interchange Authority
2. Number: INT-006-3
3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. Applicability:
   4.1. Balancing Authority.
   4.2. Transmission Service Provider.
5. Effective Date: July 1, 2010

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.1

R1.1. Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:
   R1.1.1. Energy profile (ability to support the magnitude of the Interchange).
   R1.1.2. Ramp (ability of generation maneuverability to accommodate).
   R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

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

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each On–time Request for Interchange (RFI), and to each Emergency RFI or Reliability Adjustment RFI from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B. The Balancing Authority and Transmission Service Provider need not provide evidence that it responded to any other requests.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization.
   1.2. Compliance Monitoring Period and Reset Time Frame
       The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1 The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.
1.3. **Data Retention**

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

1.4. **Additional Compliance Information**

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

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

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

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

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

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

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

2. **Levels of Non-Compliance**

2.1. **Level 1:** One occurrence\(^2\) of not responding to the Interchange Authority as described in R1.

2.2. **Level 2:** Two occurrences\(^1\) of not responding to the Interchange Authority as described in R1.

2.3. **Level 3:** Three occurrences\(^1\) of not responding to the Interchange Authority as described in R1.

\(^2\) This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.
2.4. **Level 4:** Four or more occurrences\(^1\) of not responding to the Interchange Authority as described in R1 or no evidence provided.

E. **Regional Differences**

None.

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</table>
### Timing Requirements for all Interconnections except WECC

#### Interchange Timeline with Minimum Reliability-Related Response Times

<table>
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<tr>
<th>Request for Interchange Submitted</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>If Arranged Interchange (RFI)(^3) is Submitted</strong></td>
<td>IA Assigned Time Classification</td>
<td>IA Makes Initial Distribution of Arranged Interchange</td>
<td>BA and TSP Conduct Reliability Assessments</td>
<td>IA Compiles and Distributes Status</td>
</tr>
<tr>
<td>&gt;1 hour after the RFI start time</td>
<td>ATF</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 2 hours to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;15 minutes prior to ramp start and ≤1 hour after the RFI start time</td>
<td>Late</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 10 minutes to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&lt;1 hour and ≥ 15 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥1 hour to &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
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</tr>
</tbody>
</table>

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\(^3\) Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
Example of Timing Requirements for all Interconnections except WECC
Timing Requirements for WECC

<table>
<thead>
<tr>
<th>If Arranged Interchange (RFI)^{4} is Submitted</th>
<th>IA Assigned Time Classification</th>
<th>IA Makes Initial Distribution of Arranged Interchange</th>
<th>BA and TSP Conduct Reliability Assessments</th>
<th>IA Compiles and Distributes Status</th>
<th>BA Prepares Confirmed Interchange for Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1 hour after the start time</td>
<td>ATF</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 2 hours to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>NA</td>
</tr>
<tr>
<td>&lt;10 minutes prior to ramp start and &lt;1 hour after the start time</td>
<td>Late</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 10 minutes to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≤ 3 minutes after receipt of confirmed RFI</td>
</tr>
<tr>
<td>10 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 5 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>11 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 6 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
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<td>12 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 7 minutes from Arranged Interchange receipt from IA</td>
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<td>13 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 8 minutes from Arranged Interchange receipt from IA</td>
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<td>≥ 3 minutes prior to ramp start</td>
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<td>14 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 9 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>&lt;1 hour and &gt; 15 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>≥ 1 hour and &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 39 minutes prior to ramp start</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 1 hour 58 minutes prior to ramp start</td>
</tr>
<tr>
<td>Submitted before 10:00 PPT with start time &gt; 00:00 PPT of following day</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>By 12:00 PPT of day the Arranged Interchange was received by the IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 1 hour 58 minutes prior to ramp start</td>
</tr>
</tbody>
</table>

^4 Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
## Example of Timing Requirements for WECC

- **Time Classification**
  - On Time
  - Late
  - ATF

### RFI Submit Time Relative to Start Time
- 5:50 - 4 hours before ramp start
- 8:50 - 1 hour before ramp start
- 9:35 - Assessments

### Submittal & Assessment Times
- 9:35 - 10
- 9:36 - 9
- 9:37 - 8
- 9:38 - 7
- 9:39 - 6
- 9:40 - 5

*If submitted before 10:00 PPT with start time >= 00:00 PPT of the following day then assessment is >= 2 hours and by 12:00 PPT*
A. Introduction

1. Title: Interchange Confirmation
2. Number: INT-007-1
3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. Applicability
   4.1. Interchange Authority.
5. Effective Date: January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:
   
   R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).
   
   R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry.
   
   R1.3. The following are defined:
      
      R1.3.1. Generation source and load sink.
      
      R1.3.2. Megawatt profile.
      
      R1.3.3. Ramp start and stop times.
      
      R1.3.4. Interchange duration.
   
   R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

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

D. Compliance

1. Compliance Monitoring Process
   
   1.1. Compliance Monitoring Responsibility
      
      Regional Reliability Organization.
   
   1.2. Compliance Monitoring Period and Reset Time Frame
      
      The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.
   
   1.3. Data Retention
      
      The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.
1.4. **Additional Compliance Information**

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

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.
1.4.2 Verified by spot checks in years between audits.
1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.
1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

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

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

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

2. **Levels of Non-Compliance**

2.1. **Level 1:** One occurrence\(^1\) where Interchange-related data was not verified as defined in R1.

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

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

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

E. **Regional Differences**

None

---

\(^1\) This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.
<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
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</table>
A. Introduction

1. **Title:** Interchange Authority Distributes Status
2. **Number:** INT-008-2
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.
4. **Applicability:**
   4.1. Interchange Authority.
5. **Effective Date:** August 27, 2008. (U.S.)
   NERC Board Approval: May 2, 2007

B. Requirements

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

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

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

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

C. Measures

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

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

D. Compliance

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

      Regional Reliability Organization.

   1.2. **Compliance Monitoring Period and Reset Time Frame**
The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

1.3. Data Retention

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

1.4. Additional Compliance Information

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

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

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

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

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

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

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

2. Levels of Non-Compliance

2.1. Level 1: One occurrence\(^1\) of not distributing final status and information as described in R1.

\(^1\) This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.
2.2. **Level 2**: Two occurrences\(^1\) of not distributing final status and information as described in R1.

2.3. **Level 3**: Three occurrences\(^1\) of not distributing final status and information as described in R1.

2.4. **Level 4**: Four or more occurrences\(^1\) of not distributing final status and information as described in R1 or no evidence provided.

E. **Regional Differences**

None.

**Version History**

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<td>May 2, 2006</td>
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<td>New</td>
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<td>2</td>
<td>May 2, 2007</td>
<td>Approved by BOT</td>
<td>Revised</td>
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<tr>
<td>2</td>
<td>July 21, 2008</td>
<td>Approved by FERC</td>
<td>Revised</td>
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</table>
### Timing Table

#### Request for Interchange Submitted

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>If Actual Arranged Interchange (RFI) is Submitted</strong></td>
<td>IA Makes Initial Distribution of Arranged Interchange</td>
<td>BA and TSP Conduct Reliability Assessments</td>
<td>IA Compiles and Distributes Status</td>
</tr>
<tr>
<td>≤1 hour prior to ramp start</td>
<td>&lt; 1 minute from RFI submission</td>
<td>&lt; 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC</td>
<td>&lt; 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≤20 minutes prior to ramp start</td>
<td>&lt; 1 minute from RFI submission</td>
<td>≤ 5 minutes from Arranged Interchange receipt from IA for WECC</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&gt;20 minutes to ≤1 hour prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA for WECC</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>&gt;1 hour to &lt; 4 hours prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Interchange Authority Distributes Status
2. Number: INT-008-3
3. Purpose: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.
4. Applicability:
   4.1. Interchange Authority.
5. Effective Date: July 1, 2010

B. Requirements

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

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:
   R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.
   R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame
The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

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

1.4. **Additional Compliance Information**

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

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

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

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

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

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

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

2. **Levels of Non-Compliance**

2.1. **Level 1:** One occurrence\(^1\) of not distributing final status and information as described in R1.

2.2. **Level 2:** Two occurrences\(^1\) of not distributing final status and information as described in R1.

2.3. **Level 3:** Three occurrences\(^1\) of not distributing final status and information as described in R1.

\(^{1}\) This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.
2.4. **Level 4:** Four or more occurrences\(^1\) of not distributing final status and information as described in R1 or no evidence provided.

E. **Regional Differences**

None.

**Version History**

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<td>Revised</td>
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<td>3</td>
<td>April 8, 2010</td>
<td>Approved by FERC, Effective July 1, 2010</td>
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</table>
## Timing Requirements for all Interconnections except WECC

<table>
<thead>
<tr>
<th>Request for Interchange Submitted</th>
<th>Interchange Timeline with Minimum Reliability-Related Response Times</th>
</tr>
</thead>
<tbody>
<tr>
<td>If Arranged Interchange (RFI) is Submitted</td>
<td>IA Assigned Time Classification</td>
</tr>
<tr>
<td>&gt;1 hour after the RFI start time</td>
<td>ATF</td>
</tr>
<tr>
<td>&lt;15 minutes prior to ramp start and ≤1 hour after the RFI start time</td>
<td>Late</td>
</tr>
<tr>
<td>&lt;1 hour and ≥ 15 minutes prior to ramp start</td>
<td>On-time</td>
</tr>
<tr>
<td>≥1 hour to &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>On-time</td>
</tr>
</tbody>
</table>

---

2 Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
**Example of Timing Requirements for all Interconnections except WECC**

<table>
<thead>
<tr>
<th>Time Classification</th>
<th>RFI submit time relative to start time</th>
<th>Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4 hours before ramp start</td>
<td>2 hours</td>
</tr>
<tr>
<td></td>
<td>1 hour before ramp start</td>
<td>20 minutes</td>
</tr>
<tr>
<td></td>
<td>15 minutes before ramp start</td>
<td>10 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 hours</td>
</tr>
</tbody>
</table>

- **On Time**
  - Ramp Start Time: 9:55
  - Interchange Start Time: 10:00

- **Late**
  - On Time ATF: 11:00

- **ATF**
  - Late ATF: 11:00
### Timing Requirements for WECC

<table>
<thead>
<tr>
<th>If Arranged Interchange (RFI) is Submitted</th>
<th>IA Assigned Time Classification</th>
<th>IA Makes Initial Distribution of Arranged Interchange</th>
<th>BA and TSP Conduct Reliability Assessments</th>
<th>IA Compiles and Distributes Status</th>
<th>BA Prepares Confirmed Interchange for Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1 hour after the start time</td>
<td>ATF</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 2 hours to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>NA</td>
</tr>
<tr>
<td>&lt;10 minutes prior to ramp start and ≤ 1 hour after the start time</td>
<td>Late</td>
<td>≤ 1 minute from RFI submission</td>
<td>Entities have up to 10 minutes to respond.</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≤ 3 minutes after receipt of confirmed RFI</td>
</tr>
<tr>
<td>10 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 5 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>11 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 6 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>12 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 7 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>13 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 8 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>14 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 9 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>&lt;1 hour and ≥ 15 minutes prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 10 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 3 minutes prior to ramp start</td>
</tr>
<tr>
<td>≥ 1 hour and &lt; 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 20 minutes from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 39 minutes prior to ramp start</td>
</tr>
<tr>
<td>≥ 4 hours prior to ramp start</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>≤ 2 hours from Arranged Interchange receipt from IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 1 hour 58 minutes prior to ramp start</td>
</tr>
<tr>
<td>Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day</td>
<td>On-time</td>
<td>≤ 1 minute from RFI submission</td>
<td>By 12:00 PPT of day the Arranged Interchange was received by the IA</td>
<td>≤ 1 minute from receipt of all Reliability Assessments</td>
<td>≥ 1 hour 58 minutes prior to ramp start</td>
</tr>
</tbody>
</table>

3 Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
Example of Timing Requirements for WECC

*If submitted before 10:00 PPT with start time >= 00:00 PPT of the following day then assessment is >= 2 hours and by 12:00 PPT*
A. Introduction

1. Title: Implementation of Interchange
2. Number: INT-009-1
3. Purpose: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

4. Applicability
   4.1. Balancing Authority.

5. Effective Date: January 1, 2007

B. Requirements

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

C. Measures

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

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

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

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization.
   1.2. Compliance Monitoring Period and Reset Time Frame
       The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.
   1.3. Data Retention
       The Balancing Authority and Interchange Authority shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.
   1.4. Additional Compliance Information
       Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.
       Subsequent to the initial compliance review, compliance may be:
   1.4.1 Verified by audit at least once every three years.
1.4.2 Verified by spot checks in years between audits.

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

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

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

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

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

2. Levels of Non-Compliance

2.1. Level 1: One occurrence\(^1\) of not implementing a Confirmed Interchange as described in R1.

2.2. Level 2: Two occurrences\(^1\) of not implementing a Confirmed Interchange as described in R1.

2.3. Level 3: Three occurrences\(^1\) of not implementing a Confirmed Interchange as described in R1.

2.4. Level 4: Four or more occurrences\(^1\) of not implementing a Confirmed Interchange as described in R1 or no evidence provided.

E. Regional Differences

None identified.

Version History

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</tbody>
</table>

\(^1\) This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.
A. Introduction

1. Title: Interchange Coordination Exemptions
2. Number: INT-010-1
3. Purpose: Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

4. Applicability
   
   4.1. Balancing Authority.
   
   4.2. Reliability Coordinator.

5. Effective Date: January 1, 2007

B. Requirements

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

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

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

C. Measures

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

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

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

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

       Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

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

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

1.4. Additional Compliance Information

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

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.
1.4.2 Verified by spot checks in years between audits.
1.4.3 Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.
1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

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

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority.
1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.

2. Levels of Non-Compliance

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

2.1.1 One occurrence of not submitting an Arranged Interchange as described in R1.
2.1.2 One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

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

2.2.1 Two occurrences of not submitting an Arranged Interchange as described in R1.
2.2.2 Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions is present:
2.3.1 Three occurrences of not submitting an Arranged Interchange as described in R1.

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

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

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

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

2.4.3 No evidence provided.

E. **Regional Differences**

None identified.

**Version History**

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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: May 13, 2009

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

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A. Introduction

1. **Title:** Reliability Coordination — Facilities
2. **Number:** IRO 002-1
3. **Purpose:** Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.
4. **Applicability**
   4.1. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.

R2. Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.

R3. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.

R4. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.

R5. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R6. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.
R7. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

R8. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R9. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators, that will be used to confirm that it has communication facilities in accordance with Requirements 1 and 4.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a data-link facility description document, computer print-out, training-document, or other equivalent evidence that will be used to confirm that it has data links with entities within its Reliability Coordinator Area and with neighboring Reliability Coordinators, as specified in Requirements 1 and 4.

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a letter to Transmission Operators, Balancing Authorities, Transmission Owners, Generator Owners, Generator Operators, and Load-Serving Entities, or adjacent Reliability Coordinators, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has requested the data required to support its reliability coordination tasks. (Requirement 2)

M4. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its Reliability Coordinator Area and monitoring capability of its surrounding Reliability Coordinator Areas to identify potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations.

M5. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, documentation from suppliers, operating and planning staff training documents, examples of studies, or other equivalent evidence to show that it has analysis tools in accordance with Requirement 7.

M6. Each Reliability Coordinator shall provide evidence such as equipment specifications, operating procedures, staff records of their involvement in training, or other equivalent
evidence to show that it has a backup monitoring facility that can be used to identify and monitor SOLs and IROLs. (Requirement 8)

**M7.** Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to veto planned outages to analysis tools, including final approvals for planned maintenance as specified in Requirement 9 Part 1.

**M8.** Each Reliability Coordinator shall have and provide upon request its current procedures used to mitigate the effects of analysis tool outages as specified in Requirement 9 Part 2.

### 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 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 Reliability Coordinator shall have current in-force documents used to show compliance with Measures 1 through 8.

   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: Not applicable.

2.2. Level 2: Did not confirm that the network used for data exchange to other Reliability Coordinators is secure as specified in R3.

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 Has not requested the data required to support its reliability coordination tasks. (Requirement 2)

   2.3.2 Does not control its Reliability Coordinator analysis tools, including the exercising of final approvals for planned maintenance (R7) or does not have current procedures in place to mitigate the effects of analysis tool outages as specified in R9.

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 Does not have or could not demonstrate the use of voice communication facilities (or show data links) to one or more Transmission Operators, Generator Operators or Balancing Authorities with authority over Bulk Electrical System equipment or with one or more neighboring Reliability Coordinators. (R1 and R4)

   2.4.2 Does not have real-time monitoring capability of its Reliability Coordinator Area and surrounding Reliability Coordinator Areas as specified in R5.

   2.4.3 Does not have a documented procedure for the use of its backup monitoring facilities. (R8)

E. Regional Differences

None identified.

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A. Introduction

1. Title: Reliability Coordination — Facilities
2. Number: IRO 002-2
3. Purpose: Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.
4. Applicability
   4.1. Reliability Coordinators.
5. Proposed Effective Date:

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after Board of Trustee adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.

R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.

R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.

R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators, that will be used to confirm that it has communication facilities in accordance with Requirements 1 and 3.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a data-link facility description document, computer print-out, training-document, or other equivalent evidence that will be used to confirm that it has data links with entities within its Reliability Coordinator Area and with neighboring Reliability Coordinators, as specified in Requirements 1 and 3.

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its Reliability Coordinator Area and monitoring capability of its surrounding Reliability Coordinator Areas to identify potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations.

M4. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, documentation from suppliers, operating and planning staff training documents, examples of studies, or other equivalent evidence to show that it has analysis tools in accordance with Requirement 6.

M5. Each Reliability Coordinator shall provide evidence such as equipment specifications, operating procedures, staff records of their involvement in training, or other equivalent evidence to show that it has a backup monitoring facility that can be used to identify and monitor SOLs and IROLs. (Requirement 7)

M6. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to veto planned outages to analysis tools, including final approvals for planned maintenance as specified in Requirement 8 Part 1.

M7. Each Reliability Coordinator shall have and provide upon request its current procedures used to mitigate the effects of analysis tool outages as specified in Requirement 8 Part 2.

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 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 Reliability Coordinator shall have current in-force documents used to show compliance with Measures 1 through 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. **Violation Severity Levels:**

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<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>The Reliability Coordinator has demonstrated communication facilities for both voice and data exist to all appropriate entities and that they are staffed and available but they are less than adequate.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with one appropriate entity or 2) Data links with one appropriate entity.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with two appropriate entities or 2) Data links with two appropriate entities.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with more than two appropriate entities or 2) Data links with more than two appropriate entities or 3) Communication facilities are not staffed or 4) Communication facilities are not ready.</td>
</tr>
<tr>
<td>R2</td>
<td>N/A</td>
<td>The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with one of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.</td>
<td>The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with two of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.</td>
<td>The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with three of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.</td>
</tr>
<tr>
<td>R3</td>
<td>N/A</td>
<td>The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to one of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.</td>
<td>The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to two or more of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.</td>
<td>The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to all of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with all neighboring Reliability Coordinators.</td>
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<td>Requirement</td>
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<tr>
<td>R4</td>
<td>The Reliability Coordinator's monitoring systems provide information in a way that is not easily understood and interpreted by the Reliability Coordinator's operating personnel or particular emphasis was not given to alarm management and awareness systems, automated data transfers and synchronized information systems.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that one potential or actual SOL or IROL violation is not identified.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that two or more potential and actual SOL and IROL violations are not identified.</td>
<td>The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that all potential and actual SOL and IROL violations are identified.</td>
</tr>
<tr>
<td>R5</td>
<td>The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in one SOL violations or 2) or operating reserves for a small portion of the Reliability Authority Area.</td>
<td>The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations, or 3) operating reserves.</td>
<td>The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing two or more IROLs; or one IROL and to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations and operating reserves, or 3) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or system restoration and operating reserves.</td>
<td>The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all IROLs and to system restoration, or 2) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all SOL violations and operating reserves.</td>
</tr>
<tr>
<td>Requirement</td>
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<tr>
<td><strong>R6</strong></td>
<td>The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing all pre-contingency flows, 2) analysis tools capable of assessing all post-contingency flows, or 3) all necessary wide-area overview displays exist.</td>
<td>The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing the majority of pre-contingency flows, 2) analysis tools capable of assessing the majority of post-contingency flows, or 3) the majority of necessary wide-area overview displays exist.</td>
<td>The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing a minority of pre-contingency flows, 2) analysis tools capable of assessing a minority of post-contingency flows, or 3) a minority of necessary wide-area overview displays exist.</td>
<td>The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing any pre-contingency flows, 2) analysis tools capable of assessing any post-contingency flows, or 3) any necessary wide-area overview displays exist.</td>
</tr>
<tr>
<td><strong>R7</strong></td>
<td>The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored SOLs when the main monitoring system was unavailable or 2) it has provisions to monitor SOLs when the main monitoring system is not available.</td>
<td>The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored one IROL when the main monitoring system was unavailable or 2) it has provisions to monitor one IROL when the main monitoring system is not available.</td>
<td>The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored two or more IROLS when the main monitoring system was unavailable, 2) it or a delegated entity monitored SOLs and one IROL when the main monitoring system was unavailable 3) it has provisions to monitor two or more IROLS when the main monitoring system is not available, or 4) it has provisions to monitor SOLs and one IROL when the main monitoring system was unavailable.</td>
<td><strong>R9</strong> The Reliability Coordinator failed to demonstrate that it continuously monitored its Reliability Authority Area.</td>
</tr>
<tr>
<td>Requirement</td>
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<tr>
<td>R8</td>
<td>Reliability Coordinator has approval rights for planned maintenance outages of analysis tools but does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.</td>
<td>Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools.</td>
<td>Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools and does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.</td>
<td>Reliability Coordinator approval is not required for planned maintenance.</td>
</tr>
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### E. Regional Variances

None identified.

### Version History

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<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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<td>2</td>
<td></td>
<td>Deleted R2, M3 and associated compliance elements</td>
<td>Revised</td>
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<td></td>
<td>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)</td>
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<td></td>
<td>Corrected typographical errors in BOT approved version of VSLs</td>
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</table>
A. Introduction

1. Title: Reliability Coordination — Wide-Area View
2. Number: IRO-003-2
3. Purpose: The Reliability Coordinator must have a wide-area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.
4. Applicability
   4.1. Reliability Coordinators.
5. Effective Date: January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors adjacent Reliability Coordinator Areas as necessary to ensure that, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

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 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 Reliability Coordinator shall have current in-force documents used to show compliance with Measure 1.

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: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not produce acceptable evidence to confirm that it monitors adjacent Reliability Coordinator Areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

E. Regional Differences

None identified.
## Version History

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<td>1</td>
<td>February 7, 2006</td>
<td>Adopted by Board of Trustees</td>
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<tr>
<td>2</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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</table>
A. Introduction

1. Title: Reliability Coordination — Operations Planning

2. Number: IRO-004-1

3. Purpose: Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

4. Applicability

   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Transmission Service Providers.
   4.5. Transmission Owners.
   4.6. Generator Owners.
   4.7. Generator Operators.
   4.8. Load-Serving Entities.

5. Effective Date: November 1, 2006

B. Requirements

R1. Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

R2. Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.

R3. Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.

R4. Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R5. Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators,
Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.

R6. If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.

R7. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

M1. Evidence that the Reliability Coordinator conducted next-day contingency analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System could be operated reliably in anticipated normal and Contingency conditions.

D. Compliance

1. Compliance Monitoring Process

Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Reliability Coordinator must annually self-certify compliance to its Regional Reliability Organization with the completion of the studies and action plans in Requirements R1, R2 and R3.

Exception Reporting: Reliability Coordinators will prepare a monthly report to the Regional Reliability Organization for each month that system studies were not conducted, indicating the dates that studies were not done and the reason why.

1.2. Compliance Monitoring Period and Reset Time Frame

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

1.3. Data Retention

Documentation shall be available for 3 months to provide verification that system studies were performed as required.

1.4. Additional Compliance Information

None identified.

2. Levels of Non-Compliance

2.1. Level 1: System studies were not conducted for one day in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.
2.2. **Level 2:** System studies were not conducted for 2–3 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.3. **Level 3:** System studies were not conducted for 4–5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.4. **Level 4:** System studies were not conducted for more than 5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

**E. Regional Differences**

None identified.

**Version History**

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A. Introduction

1. Title: Reliability Coordination — Operations Planning
2. Number: IRO-004-2
3. Purpose: Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

4. Applicability
   4.2. Transmission Operators.
   4.3. Transmission Service Providers.

5. Effective Date: In those jurisdictions where no regulatory approval is required, the standard shall be retired on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption. In those jurisdictions where regulatory approval is required, the standard shall be retired effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

M1. None

D. Compliance

1. Compliance Monitoring Process

Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.1. Compliance Monitoring Responsibility

1.2. Compliance Monitoring Period and Reset Time Frame

1.3. Data Retention

1.4. Additional Compliance Information
2. Violation Severity Levels

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<tbody>
<tr>
<td>R1</td>
<td>The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on one (1) occasion during a calendar month.</td>
<td>The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on two (2) to three (3) occasions during a calendar month.</td>
<td>The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on four (4) to five (5) occasions during a calendar month.</td>
<td>The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on more than five (5) occasions during a calendar month.</td>
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</table>
E. Regional Variances

Version History

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<td>Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Retired R1 through R6, and associated Measures, Data Retention, and VSLs</td>
<td>Revision</td>
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A. Introduction

1. Title: Reliability Coordination — Current Day Operations

2. Number: IRO-005-2

3. Purpose: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Transmission Service Providers.

4.5. Generator Operators.


4.7. Purchasing-Selling Entities.

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.
R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities’ parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission
Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records, computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

M3. If a potential or actual IROL violation occurs, 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, system
event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)

M4. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operating logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)

M6. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.

M8. The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)

M9. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)

M10. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator’s Area (Requirement 11 Part 1)

M11. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include,
but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)

M12. If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)

M14. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes. (Requirement 14 Part 2)

M15. The Reliability Coordinator 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 evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.

M16. The Reliability Coordinator 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 evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.

M17. The Reliability Coordinator 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 evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

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 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**

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider 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**

None.

2. **Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider**

2.1. **Level 1**: Not applicable.

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 Did not follow the Reliability Coordinator’s directives in accordance with R8 Part 2).

   2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

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

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

3.2. **Level 2:** Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)

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

   3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)

   3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)

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 meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)

   3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)

   3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)

   3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)

   3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)

   3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

   3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)

   3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)
3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)

3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator’s wide-area view ) (Requirement 14 Part 1)

3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

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 operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

E. Regional Differences

None identified.

Version History

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<td>August 31, 2006</td>
<td>Added three items that were inadvertently left out to “Applicability” section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities</td>
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A. Introduction

1. Title: Reliability Coordination — Current Day Operations
2. Number: IRO-005-2a
3. Purpose: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. Applicability

   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Transmission Service Providers.
   4.5. Generator Operators.
   4.7. Purchasing-Selling Entities.

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

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

   R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
   R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.
   R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.
   R1.4. System real and reactive reserves (actual versus required).
   R1.5. Capacity and energy adequacy conditions.
   R1.6. Current ACE for all its Balancing Authorities.
   R1.7. Current local or Transmission Loading Relief procedures in effect.
   R1.8. Planned generation dispatches.
   R1.9. Planned transmission or generation outages.
   R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.
R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities’ parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission
Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records, computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

M3. If a potential or actual IROL violation occurs, 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, system
event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)

M4. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operating logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)

M6. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operating logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.

M8. The Transmission Operators and Balancing Authorities 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 evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)

M9. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)

M10. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator’s Area (Requirement 11 Part 1)

M11. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include,
but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)

M12. If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)

M14. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes. (Requirement 14 Part 2)

M15. The Reliability Coordinator 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 evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.

M16. The Reliability Coordinator 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 evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.

M17. The Reliability Coordinator 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 evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

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

1.3. Data Retention

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider 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

None.

2. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider

2.1. Level 1: Not applicable.

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 Did not follow the Reliability Coordinator’s directives in accordance with R8 Part 2).

2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

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

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

3.2. **Level 2**: Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)

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

3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)

3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)

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 meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)

3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)

3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)

3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)

3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)

3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)

3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)
3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)

3.4.10 Did not provide Transmission Service Providers with SOLs or IROls (within the Reliability Coordinator’s wide-area view ) (Requirement 14 Part 1)

3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

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 operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

4.4.2 Did not respect the SOLs or IROls in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

E. Regional Differences

None identified.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tbody>
<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
</tr>
<tr>
<td>1</td>
<td>February 2, 2006</td>
<td>Approved by Board of Trustees</td>
<td>Revised</td>
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<tr>
<td>2</td>
<td>August 31, 2006</td>
<td>Added three items that were inadvertently left out to “Applicability” section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities</td>
<td>Errata</td>
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<td>2</td>
<td>November 1, 2006</td>
<td>Approved by Board of Trustees</td>
<td>Revised</td>
</tr>
<tr>
<td>2</td>
<td>June 26, 2007</td>
<td>Approved by FERC: Missing Measures and Compliance Elements</td>
<td>Revised</td>
</tr>
<tr>
<td>2a</td>
<td>November 5, 2009</td>
<td>Added Appendix 1 – Interpretation of R12 approved by BOT on November 5, 2009</td>
<td>Interpretation</td>
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</tbody>
</table>
### Appendix 1

<table>
<thead>
<tr>
<th>Requirement Number and Text of Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TOP-005-1 Requirement R3</strong></td>
</tr>
<tr>
<td>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.</td>
</tr>
</tbody>
</table>

> The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded special protection systems. [Underline added for emphasis.]

<table>
<thead>
<tr>
<th>IRO-005-1 Requirement R12</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R12.</strong> Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. [Underline added for emphasis.]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PRC-012-0 Requirements R1 and R1.3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1.</strong> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:</td>
</tr>
<tr>
<td><strong>R1.3.</strong> Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</td>
</tr>
</tbody>
</table>

### Background Information for Interpretation

The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”

The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability...
obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.
A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations

2. **Number:** IRO-005-3

3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. **Applicability**
   4.1. Reliability Coordinators.
   4.2. Balancing Authorities.
   4.3. Transmission Operators.
   4.4. Transmission Service Providers.
   4.5. Generator Operators.
   4.7. Purchasing-Selling Entities.

5. **Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

**R1.** Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

- **R1.1.** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

- **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.

- **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.

- **R1.4.** System real and reactive reserves (actual versus required).

- **R1.5.** Capacity and energy adequacy conditions.

- **R1.6.** Current ACE for all its Balancing Authorities.
R1.7. Current local or Transmission Loading Relief procedures in effect.
R1.8. Planned generation dispatches.
R1.9. Planned transmission or generation outages.
R1.10. Contingency events.

R2. Each Reliability Coordinator shall monitor its Balancing Authorities’ parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)

M3. The Reliability Coordinator 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 evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)

M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.

M6. The Transmission Operators and Balancing Authorities 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 evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance.
outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator’s Area (Requirement 8 Part 1)

M9. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 9)

M10. If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 10)

M11. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes. (Requirement 11 Part 2)

M12. The Reliability Coordinator 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 evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.

M13. The Reliability Coordinator 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 evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.

M14. The Reliability Coordinator 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 evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

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 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

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider 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

None.
2. **Violation Severity Levels:**

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<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-1 R1.1 through R1.10.</td>
<td>The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-1 R1.1 through R1.10.</td>
<td>The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.</td>
<td>The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.</td>
</tr>
<tr>
<td>R1.1</td>
<td>The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.2</td>
<td>The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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<td>-------------</td>
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<tr>
<td>R1.3</td>
<td>The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.4</td>
<td>The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.5</td>
<td>The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.6</td>
<td>The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.7</td>
<td>The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.8</td>
<td>The Reliability Coordinator failed to monitor planned generation dispatches.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R1.9</td>
<td>The Reliability Coordinator failed to monitor planned transmission or generation outages.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
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<td>Severe</td>
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<tr>
<td>R1.10</td>
<td>The Reliability Coordinator failed to monitor contingency events.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>R2</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.</td>
<td>The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.</td>
<td>The Reliability Coordinator failed to monitor its Balancing Authorities’ parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.</td>
</tr>
<tr>
<td>R3</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.</td>
<td>The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.</td>
</tr>
<tr>
<td>R4</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.</td>
</tr>
</tbody>
</table>
### Requirement 5 (R5)

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R5</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator monitored system frequency and its Balancing Authorities’ performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.</td>
<td>The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.</td>
</tr>
</tbody>
</table>

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The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities’ performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R6</td>
<td>N/A</td>
<td>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans, or the Reliability Coordinator coordinated pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in the real-time reliability analysis timeframe but failed to coordinate pending generation and transmission maintenance outages in the next-day reliability analysis timeframe.</td>
<td>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations, or the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</td>
<td>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</td>
</tr>
<tr>
<td>R7</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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<tr>
<td>-------------</td>
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</tr>
<tr>
<td>R8</td>
<td>N/A</td>
<td>The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.</td>
<td>The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.</td>
<td>The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.</td>
</tr>
<tr>
<td>R9</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
</tr>
<tr>
<td>-------------</td>
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</tr>
<tr>
<td>R10</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.</td>
</tr>
<tr>
<td>R11</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.</td>
</tr>
<tr>
<td>R12</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.</td>
<td>N/A</td>
<td>The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.</td>
</tr>
</tbody>
</table>
E. Regional Differences

None identified.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
</tr>
<tr>
<td>1</td>
<td></td>
<td>Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17</td>
<td>Revised</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Retired M2 and M3; modified M9 and M12; retired M13</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Made conforming changes to data retention</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Retired VSLs associated with R2, R3, R5, R16 and R17;</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>Modified VSLs associated with R9 and R13, and R14</td>
<td></td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Reliability Coordination — Transmission Loading Relief
2. Number: IRO-006-3
3. Purpose: Regardless of the process it uses, the Reliability Coordinator must direct its Balancing Authorities and Transmission Operators to return the transmission system to within its Interconnection Reliability Operating Limits as soon as possible, but no longer than 30 minutes. The Reliability Coordinator needs to direct Balancing Authorities and Transmission Operators to execute actions such as reconfiguration, redispatch, or load shedding until relief requested by the TLR process is achieved.

4. Applicability
   4.1. Reliability Coordinators.
   4.2. Transmission Operators.
   4.3. Balancing Authorities.

5. Proposed Effective Date:
   E.2 effective upon BOT adoption.
   Changes to TLR 3b and 4 for IRO-006-2 to be announced.

B. Requirements

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

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

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


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

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

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

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

C. Measures

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

D. Compliance

1. Compliance Monitoring Process

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

1.1. Compliance Monitoring Responsibility

Not specified.

1.2. Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

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

E. Regional Differences

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

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

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

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

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

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

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

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

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

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

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

• The contribution of the market area load is based on the present demand at each individual bus.

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

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

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

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

• Distribution Factor (no tag to calculate this value from)

• Impact on Interface value (cannot be calculated without Distribution Factor)

• Impact Weighting Factor (cannot be calculated without Distribution Factor)

• Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)

• Interface Reduction (cannot be calculated without Distribution Factor)

• Transaction Reduction (cannot be calculated without Distribution Factor)

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

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

Under the header “IDC Calculations and Reporting” in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: “In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:
<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.</td>
<td>The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.</td>
<td>The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.</td>
<td>The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S4</td>
<td>To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.)</td>
<td>The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.</td>
</tr>
</tbody>
</table>

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

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

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

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow existing market flow to</td>
<td>The currently flowing MW amount is</td>
</tr>
</tbody>
</table>
maintain or reduce its current MW amount. | the amount of market flow existing after the RTO has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead.

| S2 | To allow market flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour. | This is the difference between the current hour unconstrained market flow and the current market flow. If the current-hour unconstrained market flow is not available, the IDC will use the most recent market flow since the TLR was first issued or, if not available, the market flow at the time the TLR was first issued. |

| S3 | To allow a market flow to increase to its next-hour desired amount. | This is the difference between the next hour and current hour unconstrained market flow. |
Transmission Loading Relief Procedure — Eastern Interconnection

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

Applicability
This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure
   1.1. **Initiation only by Reliability Coordinator.** A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure and shall do so at 1) the Reliability Coordinator’s own request, or 2) upon the request of a Transmission Operator.
   1.2. **Mitigating transmission constraints.** A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or actual System Operating Limit (SOL) violations or Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC.
      1.2.1. **Requesting relief on tie facilities.** Any Transmission Operator who operates the tie facility shall be allowed to request relief from its Reliability Coordinator.
         **Interchange Transaction priority on tie facilities.** The priority of the Interchange Transaction(s) to be curtailed shall be determined by the Transmission Service reserved on the Transmission Service Provider’s system who requested the relief.
   1.3. **Order of TLR Levels and taking emergency action.** The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical order (Section 2, “TLR Levels”). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.
   1.4. **Notification of TLR Procedure implementation.** The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).
      1.4.1. **Notifying other Reliability Coordinators.** The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.
   **Actions expected.** The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.
1.4.2. **Notifying Transmission Operators and Balancing Authorities.** The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.

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

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

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

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

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

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

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

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

1.6.3. **Questionable IDC results.** Any Reliability Coordinator (or Transmission Operator through its Reliability Coordinator) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:
• Missing Interchange Transactions that are known to contribute to the Constraint.
• Significant change in transmission system topology.
• TDF matrix error.

Impacts of questionable IDC results may include:
• Curtailment that would have no effect on, or aggravate the constraint.
• Curtailment that would initiate a constraint elsewhere.

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

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

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

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

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

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

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

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

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

1.9.3. **Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for “lessons learned.”
2. **Transmission Loading Relief (TLR) Levels**

**Introduction**

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

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

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

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

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

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

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

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

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

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

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions to be implemented according to their transmission reservation priority. The time for
being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. **TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service**

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

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

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

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

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

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

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

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

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

2.4. **TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation**

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b:

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.4.2. **Curtailment procedures to mitigate an SOL or IROL.** The Reliability Coordinator shall curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, “Interchange Transaction Curtailment Order” in the current hour to mitigate an SOL or IROL as well as reallocating, in accordance with Section 6 of this document, to a determined flow for the top of the next hour.

The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7 “Interchange Transaction Curtailments during TLR Level 3b.”

2.5. **TLR Level 4 — Reconfigure Transmission**

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

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

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

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

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

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

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

2.6.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider’s Network Integration Transmission Service and Native Load, as required by the Transmission Provider’s filed tariff. This is described in Section 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.”
2.6.2.3. **Step 3 — Curtail Interchange Transactions using Firm Transmission Service.** The Reliability Coordinator shall curtail or reallocate on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions), those Interchange Transactions as calculated in Section 7.2.2 over the Constrained Facilities. (See also Section 6, “Interchange Transaction Reallocation during TLR 3a and 5a.”) The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider’s tariff. Available redispatch options will continue to be implemented.

2.7. **TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation**

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b:

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

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

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

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

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

2.8. TLR Level 6 — Emergency Procedures

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

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

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

2.9. TLR Level 0 — TLR concluded

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

3.1. Priority of Interchange Transactions

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

**Transmission Service Priorities**

- **Priority 0.** Next-hour Market Service — NX*
- **Priority 1.** Service over secondary receipt and delivery points — NS
- **Priority 2.** Non-Firm Point-to-Point Hourly Service — NH
- **Priority 3.** Non-Firm Point-to-Point Daily Service — ND
- **Priority 4.** Non-Firm Point-to-Point Weekly Service — NW
- **Priority 5.** Non-Firm Point-to-Point Monthly Service — NM
- **Priority 6.** Network Integration Transmission Service from sources not designated as network resources — NN
- **Priority 7.** Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

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

3.2. Curtailment of Interchange Transactions Using Non-firm Transmission Service

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

3.2.1.1. **TLR Level 3a.** Enable Interchange Transactions using a higher Transmission reservation priority to be implemented, or

3.2.1.2. **TLR Level 3b.** Mitigate an SOL or IROL violation.

3.3. Curtailment of Interchange Transactions Using Firm Transmission Service

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

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

3.3.1.2. **TLR Level 5b.** Mitigate a SOL or IROL violation that remains after all Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.
4. Mitigating Constraints On and Off the Contract Path during TLR

Introduction

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

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

4.1. Constraints ON the Contract Path

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

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

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

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

4.2. Constraints OFF the Contract Path

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

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

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

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

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

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

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

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

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

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

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

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

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

The calculation of the flow on a Constrained Facility due to Network Integration Transmission Service or service to Native Load shall be based on the Generation Shift Factors (GSFs) of a Balancing Authority’s assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs shall be calculated from a single bus location in the IDC. The IDC shall report all generators assigned to native load for which the GLDF is greater than or equal to the Curtailment Threshold.
6. Interchange Transaction Reallocation During TLR Levels 3a and 5a

Introduction

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

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

**TLR Level 5a** accomplishes Reallocation by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow new Interchange Transactions using Firm Point-to-Point Transmission Service to begin, also on a pro-rata basis. (See Requirement 2.6, “TLR Level 5a.”)

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

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

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

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

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

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

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

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

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

6.2. Communication and Timing Requirements

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

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

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

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

6.2.2.2. The approved tag submission deadline for Reallocation shall cease to be in effect as soon as the TLR level is reduced to 1 or 0.
6.2.3. **Off-hour Transactions.** Interchange Transactions with a start time other than xx:00 shall be considered for Reallocation at xx+1:00. For example, an Interchange Transaction with a start time of 01:05 and whose Tag was submitted at 00:15 will be considered for Reallocation at 02:00.

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

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

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

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

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

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

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

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

6.2.5.5. Subsequent required reports before 01:00 shall allow the Reliability Coordinators to include those Interchange Transactions whose tags were submitted to the IDC after the Approved-Tag Submission Time for Reallocation and were given the HOLD status (not permitted to PROCEED). Transactions at or above the Curtailment Threshold that are not indicated as “PROCEED” on Reload/Reallocation Report shall not be permitted to start or increase the next hour.
Discussion: Note that TLR 2 does not initiate the approved tag submission deadline for Reallocation, but a TLR3a or 5a does. It is, however, important to recognize the time when a TLR 2 is called, where applicable, to determine the status of a held transaction – “CURTAILED” if tagged before the TLR was called but “HOLD” if tagged after the TLR was called.

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

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

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

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

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

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.) It must be emphasized that the preferred time period is not a requirement, and should not in any way impede a Reliability Coordinator’s ability to declare a TLR 3a, 3b, 4, 5a, or 5b whenever the need arises.
7. Interchange Transaction Curtailments During TLR Level 3b

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

TLR Level 3b curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold in the current hour while Reallocating to a determined flow for the top of the next hour (See Requirement 2.4, “TLR Level 3b.”).

Requirements

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

7.2. The Reliability Coordinator shall consider only those Interchange Transactions at or above the Curtailment Threshold for curtailment or holding.

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

7.4. The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission Service in accordance with Section 6 of this document for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

7.4.1. If issued prior to XX: 25, Non-firm Interchange Transactions will be curtailed to meet the desired current hour relief

7.4.1.1. At XX: 25 a Reallocation will be performed to maintain the desired flow at the top of the following hour

7.4.2. If issued after XX: 25, Non firm Interchange Transactions will be curtailed to meet the desired current hour relief and a Reallocation will be performed to maintain the target flow identified for the current hour.

7.4.3. Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).
7.5. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start as explained in Appendix F, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”

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

7.7. The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include:

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

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

7.8. The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

7.9. The Reliability Coordinator will no longer be required to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b.
Appendices for Transmission Loading Relief Standard

Appendix B. Transaction Curtailment Formula.
Appendix C. Sample NERC Transmission Loading Relief Procedure Log.
Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.
Appendix E. How the IDC Handles Reallocation.
   Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.
   Section E2: Timing Requirements.
Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.
Appendix G. Examples of On-Path and Off-Path Mitigation.
Appendix A. Transaction Management and Curtailment Process

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

**Example**

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

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

<table>
<thead>
<tr>
<th>Transaction ID</th>
<th>Initial Transaction</th>
<th>Distribution Factor</th>
<th>(1)*(2) Impact On Interface</th>
<th>(2)/(2TOT) Impact weighting factor</th>
<th>(3)/(4) Weighted Max Interface Reduction</th>
<th>(5)/(5TOT) (Relief Requested) Interface Reduction</th>
<th>(6)/(2) Transaction Reduction</th>
<th>(1)-(7) New Transaction Amount</th>
<th>(8)* Adjusted Impact On Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-D(1)</td>
<td>800</td>
<td>0.6</td>
<td>480</td>
<td>0.34</td>
<td>164.57</td>
<td>209.73</td>
<td>349.54</td>
<td>450.46</td>
<td>270.27</td>
</tr>
<tr>
<td>A-D(2)</td>
<td>200</td>
<td>0.6</td>
<td>120</td>
<td>0.34</td>
<td>41.14</td>
<td>52.43</td>
<td>87.39</td>
<td>112.61</td>
<td>67.57</td>
</tr>
<tr>
<td>B-D</td>
<td>800</td>
<td>0.15</td>
<td>120</td>
<td>0.09</td>
<td>10.29</td>
<td>13.11</td>
<td>87.39</td>
<td>712.61</td>
<td>106.89</td>
</tr>
<tr>
<td>C-D</td>
<td>100</td>
<td>0.2</td>
<td>20</td>
<td>0.11</td>
<td>2.29</td>
<td>2.91</td>
<td>14.56</td>
<td>85.44</td>
<td>17.09</td>
</tr>
<tr>
<td>E-B</td>
<td>100</td>
<td>0.05</td>
<td>5</td>
<td>0.03</td>
<td>0.14</td>
<td>0.18</td>
<td>3.64</td>
<td>96.36</td>
<td>4.82</td>
</tr>
<tr>
<td>F-B</td>
<td>100</td>
<td>0.15</td>
<td>15</td>
<td>0.09</td>
<td>1.29</td>
<td>1.64</td>
<td>10.92</td>
<td>89.08</td>
<td>13.36</td>
</tr>
</tbody>
</table>

**Example 1**

<table>
<thead>
<tr>
<th>Transaction ID</th>
<th>Initial Transaction</th>
<th>Distribution Factor</th>
<th>(1)*(2) Impact On Interface</th>
<th>(2)/(2TOT) Impact weighting factor</th>
<th>(3)/(4) Weighted Max Interface Reduction</th>
<th>(5)/(5TOT) (Relief Requested) Interface Reduction</th>
<th>(6)/(2) Transaction Reduction</th>
<th>(1)-(7) New Transaction Amount</th>
<th>(8)* Adjusted Impact On Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2100</td>
<td>1.75</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>219.71</td>
<td>280.00</td>
</tr>
</tbody>
</table>

**Example 2**

<table>
<thead>
<tr>
<th>Transaction ID</th>
<th>Initial Transaction</th>
<th>Distribution Factor</th>
<th>(1)*(2) Impact On Interface</th>
<th>(2)/(2TOT) Impact weighting factor</th>
<th>(3)/(4) Weighted Max Interface Reduction</th>
<th>(5)/(5TOT) (Relief Requested) Interface Reduction</th>
<th>(6)/(2) Transaction Reduction</th>
<th>(1)-(7) New Transaction Amount</th>
<th>(8)* Adjusted Impact On Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2100</td>
<td>1.15</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>334.35</td>
<td>280.00</td>
</tr>
</tbody>
</table>

**Example 3**

<table>
<thead>
<tr>
<th>Transaction ID</th>
<th>Initial Transaction</th>
<th>Distribution Factor</th>
<th>(1)*(2) Impact On Interface</th>
<th>(2)/(2TOT) Impact weighting factor</th>
<th>(3)/(4) Weighted Max Interface Reduction</th>
<th>(5)/(5TOT) (Relief Requested) Interface Reduction</th>
<th>(6)/(2) Transaction Reduction</th>
<th>(1)-(7) New Transaction Amount</th>
<th>(8)* Adjusted Impact On Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2100</td>
<td>3.55</td>
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<tr>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>108.31</td>
<td>280.00</td>
</tr>
</tbody>
</table>
Appendix C. Sample NERC Transmission Loading Relief Procedure Log

**NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG**

<table>
<thead>
<tr>
<th>INITIAL CONDITIONS</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Limiting Flowgate (LIMIT)</td>
<td>Rating</td>
</tr>
<tr>
<td>Contingent Flowgate (CONT.)</td>
<td>ODF</td>
</tr>
</tbody>
</table>

**TLR Levels**

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

**TLR ACTIONS**

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

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

Example of Results of Calculation Method

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

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

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

<table>
<thead>
<tr>
<th>Sink Reliability Coordinator</th>
<th>Service Point</th>
<th>Scaled P Max</th>
<th>Flowgate Native Load MW</th>
<th>Current Native Load Relief</th>
<th>Native Load Responsibility Acknowledgement</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Inc/Dec</td>
<td>Current Hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Acknowledge Time</td>
<td>Total MW Resp.</td>
</tr>
<tr>
<td>EES</td>
<td>EES</td>
<td>8429.7</td>
<td>2991.4</td>
<td>0.0</td>
<td>128.9</td>
</tr>
<tr>
<td></td>
<td>LAGN</td>
<td>1514.0</td>
<td>718.6</td>
<td>0.0</td>
<td>31.0</td>
</tr>
<tr>
<td></td>
<td>SOCO</td>
<td>5089.2</td>
<td>401.1</td>
<td>0.0</td>
<td>17.3</td>
</tr>
<tr>
<td></td>
<td>CLEC</td>
<td>235.7</td>
<td>18.0</td>
<td>0.0</td>
<td>0.8</td>
</tr>
<tr>
<td></td>
<td>LEPA</td>
<td>22.8</td>
<td>4.1</td>
<td>0.0</td>
<td>0.2</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>0.0</td>
<td></td>
</tr>
</tbody>
</table>

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

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

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

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

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

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

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

Reloading/Reallocation Transaction Status
Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.
1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase. Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

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

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

**Reallocation/Reloading Priorities**

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, “Principles for Mitigating Constraints On and Off the Contract Path.” This is called the “Constrained Path Method,” or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

**Total Flow Value on a Constrained Facility for Next Hour**

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:
• Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,

• SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and

• Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.
E2. Timing Requirements

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

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.

2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the IDC Calculations and Reporting section below).

Re-Issuing of a TLR Level 2 or Higher

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

IDC Assistance with Next Hour Point-to-Point Transactions

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

### Example 1

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network and Native Load</td>
<td>-100 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>850 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Service to hold for Reallocation</td>
<td>850 MW – 800 MW = 50 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Service</td>
<td>950 MW – 50 MW = 900 MW</td>
</tr>
</tbody>
</table>

### Example 2

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network and Native Load</td>
<td>50 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>1000 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Service to hold for Reallocation</td>
<td>1000 MW – 800 MW = 200 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Service</td>
<td>950 MW – 200 MW = 750 MW</td>
</tr>
</tbody>
</table>

### Example 3

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network and Native Load</td>
<td>-200 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>750 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Service to hold for Reallocation</td>
<td>750 MW – 800 MW = -50 MW None are held</td>
</tr>
</tbody>
</table>
For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

**IDC Calculations and Reporting**

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

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

2. In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.</td>
<td>The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.</td>
<td>The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.</td>
<td>The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.</td>
</tr>
</tbody>
</table>
Priority | Purpose | Explanation and Conditions
---|---|---
S4 | To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.) | The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

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

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

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

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

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

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

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

**Tag Reloading for TLR Levels 1 and 0**

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.
New Tag Alarming
Those Interchange Transactions that are at or above the Curtailment Threshold and are not candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment
The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.

2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.

3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples
The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.
Example 1 – Transaction curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>20 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>40 MW</td>
</tr>
</tbody>
</table>

![Graph showing energy profiles and sub-priorities](image)

**Sub-priorities for Transaction MW:**

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to current hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Load to next hour Energy Profile</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 2 – Transaction curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW, so no change in MW value</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>20 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>20 MW (no curtailment)</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>40 MW</td>
</tr>
</tbody>
</table>

**Sub-Priority** | **MW Value** | **Explanation**
---|---|---
S1 | 20 MW | Maintain current flow (not curtailed)
S2 | +0 MW | Reload to lesser of current and next-hour Energy Profile
S3 | +20 MW | Next-hour Energy Profile is 40 MW
S4 | |
Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

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

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Reduce flow to next-hour Energy Profile (20MW)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 5 — TLR Issued before Transaction was scheduled to start

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>0 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>0 MW (Transaction scheduled to start after TLR initiated)</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td>+0</td>
<td>Tag submitted prior to TLR</td>
</tr>
</tbody>
</table>
Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

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

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

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

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

   b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.
Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.

1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.
3. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
4. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.
5. Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).
Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.

If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.
Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.

1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.
Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.

1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.
Appendix G. Examples of On-Path and Off-Path Mitigation

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

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

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

Case 2:  
E is a non-firm hourly path, C is firm; E has Constraint at #2
- Although C is providing Firm Service, the Constraint is not on C’s system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Point-to-Point Transmission Service, even though it was using firm service from C. That is, when the constraint is on the Contract Path, the Interchange Transaction takes on the priority of the link with the Constrained Facility (Principle 1).
Case 3:  E is a non-firm hourly path, C is firm, B has Constraint at #1

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

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

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

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

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on another system, to mitigate Constraint #2 in E before the firm A-D transaction is curtailed (Principle 2).
- A, C, D, may be requested by E to try to reconfigure transmission to mitigate Constraint #2 in E at E’s expense (Principle 2).
Case 6: The entire path (A-E-C-D) is firm; B has Constraint at #1.

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

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

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

1. Title: Reliability Coordination — Transmission Loading Relief (TLR)
2. Number: IRO-006-4.1
3. Purpose: The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.
4. Applicability:
   4.1. Reliability Coordinators.
   4.2. Transmission Operators.
   4.3. Balancing Authorities.
5. Proposed Effective Date: First day of first quarter after BOT adoption.

B. Requirements

R1. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a “local” (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.

R1.2. The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the WECC Unscheduled Flow Reduction Procedure provided at:

R1.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at:
http://www.ercot.com/mktrules/protocols/current.html

Note: the URL has changed.
R2. The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

R3. Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

R4. When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R5. During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

C. Measures

M1. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that demonstrate when Eastern Interconnection, WECC, or ERCOT Interconnection-wide transmission loading relief procedures are implemented, the implementation follows the respective established procedure as specified in this standard (R1, R1.1, R1.2 and R1.3).

M2. Each Reliability Coordinator shall be capable of providing evidence (such as written documentation) that the Transmission Operator experiencing the potential or existing SOL or IROL violations is a party to the local transmission loading relief or congestion management procedures when these procedures have been implemented (R2).

M3. Each Reliability Coordinator shall be capable of providing evidence (such as NERC meeting minutes) that the local procedure has received prior approval by the ERO when such procedure is used as a substitute for curtailment as directed by the Interconnection-wide procedure (R3).

M4. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that the responding Reliability Coordinator complied with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator when requested to curtail an Interchange Transaction that crosses an Interconnection boundary (R4).

M5. Each Reliability Coordinator and Balancing Authority shall be capable of providing evidence (such as Interchange Transaction Tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts) that
they have complied with applicable Interchange scheduling standards INT-001, INT-003, and INT-004 during the implementation of relief procedures, up to the point emergency action is necessary (R5).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

The Reliability Coordinator shall maintain evidence for eighteen months for M1, M4, and M5.

The Reliability Coordinator shall maintain evidence for the duration the Transmission Operator is party to the procedure in effect plus one calendar year thereafter for M2.

The Reliability Coordinator shall maintain evidence for the approved duration of the procedure in effect plus one calendar year thereafter for M3.

1.4. Additional Compliance Information

Each Reliability Coordinator and Balancing Authority shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually and reporting by exception. The Compliance Monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

Each Reliability Coordinator and Balancing Authority shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within 5 days of a request as part of an investigation upon complaint:

1.4.1 Operations logs, voice recordings or transcripts of voice recordings or other documentation providing the evidence of its compliance to all the requirements for all Interconnection-wide TLR procedures that it has implemented during the review period.

1.4.2 TLR reports.

2. Violation Severity Levels

2.1. Lower. There shall be a lower violation severity level if any of the following conditions exist:

2.1.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates one (1) requirement of the applicable Interconnection-wide procedure (R1)
2.1.2 The Reliability Coordinators or Balancing Authorities did not comply with applicable Interchange scheduling standards during the implementation of the relief procedures, up to the point emergency action is necessary (R5).

2.1.3 When requested to curtail an Interchange Transaction that crosses an Interconnection boundary utilizing an Interconnection-wide procedure, the responding Reliability Coordinator did not comply with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator (R4).

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

2.2.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated two (2) to three (3) requirements of the applicable Interconnection-wide procedure (R1).

2.3. High. There shall be a high violation severity level if any of the following conditions exist:

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

2.4. Severe. There shall be a severe violation severity level if any of the following conditions exist:

2.4.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated six (6) or more of the requirements of the applicable Interconnection-wide procedure (R1).

2.4.2 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures to relieve congestion but the Transmission Operator experiencing the congestion was not a party to those procedures (R2).

2.4.3 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures as a substitute for curtailment as directed by the Interconnection-wide procedure but the local procedure had not received prior approval from the ERO (R3).

2.4.4 While attempting to mitigate an existing IROL violation in the Eastern Interconnection, the Reliability Coordinator applied TLR as the sole remedy for an existing IROL violation.

2.4.5 While attempting to mitigate an existing constraint in the Western Interconnection using the “WSCC Unscheduled Flow Mitigation Plan”, the Reliability Coordinator did not follow the procedure correctly.

2.4.6 While attempting to mitigate an existing constraint in ERCOT using Section 7 of the ERCOT Protocols, the Reliability Coordinator did not follow the procedure correctly.
E. Regional Differences

1. **PJM/MISO Enhanced Congestion Management**
   (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004. To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

   This section on Regional Differences is highlighted for transfer to NAESB following completion of the MISO/PJM/SPP field test as described in the white paper.

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

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

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

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

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

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

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

   Section 5 of Attachment 1-IRO-006-1 requires that the “Per Generator Method without Counter Flow” methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each balancing authority.
SPP shall use a “Market Flow Calculation” methodology to calculate the portion of parallel flows on all facilities included in the RTO’s “Coordinated Flowgate List” due to NI service or service to NL of each balancing authority.

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

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

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

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

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

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

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

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

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

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

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.</td>
<td>The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.</td>
<td>The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.</td>
<td>The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S4</td>
<td>To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared</td>
<td>The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same</td>
</tr>
</tbody>
</table>
to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.) priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

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

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

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

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow existing market flow to maintain or reduce its current MW amount.</td>
<td>The currently flowing MW amount is the amount of market flow existing after the RTO has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow market flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour.</td>
<td>This is the difference between the current hour unconstrained market flow and the current market flow. If the current-hour unconstrained market flow is not available, the IDC will use the most recent market flow since the TLR was first issued or, if not available, the market flow at the time the TLR was first issued.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a market flow to increase to its next-hour desired amount.</td>
<td>This is the difference between the next hour and current hour unconstrained market flow.</td>
</tr>
</tbody>
</table>

To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.
F. Associated Documents

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
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<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
</tr>
<tr>
<td>1</td>
<td>August 8, 2005</td>
<td>Revised Attachment 1</td>
<td>Revision</td>
</tr>
<tr>
<td>3</td>
<td>February 26, 2007</td>
<td>Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure</td>
<td>Revision</td>
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<tr>
<td>4</td>
<td>October 23, 2007</td>
<td>Approved by Board of Trustees</td>
<td>Revision</td>
</tr>
<tr>
<td>4.1</td>
<td>April 15, 2009</td>
<td>The URL in R1.2. was corrected.</td>
<td>Errata</td>
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</table>
Attachment 1 — IRO-006

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose
This standard defines procedures for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator.

Applicability
This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

1.1. Initiation only by Reliability Coordinator. A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure.

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

1.2. Mitigating SOL and IROL violations. A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent or mitigate Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. However, the TLR procedure is an inappropriate and ineffective tool as a sole means to mitigate existing IROL violations due to the time required to implement the procedure. Reconfiguration, redispatch, and load shedding are more timely and effective in mitigating existing IROL violations.

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

1.4. Notification of TLR Procedure implementation. The Reliability Coordinator initiating the use of the TLR

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted. Please see the mapped document to see which items were move to NAESB and what future changes are expected.
Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

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

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

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

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

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

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

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

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

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

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

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

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

Impacts of questionable IDC results may include:

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

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

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

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

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

1.8.1 **Providing information.** Transmission Operators and Balancing Authorities within the Reliability Coordinator’s Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.
1.8.2 **Market Committee reviews.** The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

1.8.3 **Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for “lessons learned.”

The Market Committee no longer exists and this requirement will be removed in Phase 3.
2. Transmission Loading Relief (TLR) Levels

Introduction

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

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

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

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

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

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

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

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

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
2.3 TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b:

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.5 TLR Level 4 — Reconfigure Transmission

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

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

2.5.2. Reconfiguration procedures. The issuance of a TLR Level 4 shall result in the curtailment, in the current hour and the next hour, of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold that impact the Constrained
Facilities. If a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint.

2.6. **TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service**

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

2.7. **TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation**

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b:

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.
2.8. Curtailment of Interchange Transactions Using Firm Transmission Service

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

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

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

2.9. TLR Level 6 — Emergency Procedures

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

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

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

2.10 TLR Level 0 — TLR concluded

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

3. Requirements

3.1 The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.
3.2 The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

3.2.1 If issued prior to XX: 25, Non-firm Interchange Transactions will be curtailed to meet the desired current hour relief

4.2.1.1 At XX: 25 a Reallocation will be performed to maintain the desired flow at the top of the following hour

3.2.2 If issued after XX: 25, Non firm Interchange Transactions will be curtailed to meet the desired current hour relief and a Reallocation will be performed to maintain the target flow identified for the current hour.

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

3.3 The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include: (recommended to be moved to Attachment 2)

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

3.3.2 Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after XX:25 or issuance of TLR 3b (see Case 3 in Appendix F). (recommended to be moved to Attachment 2)

3.4 The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called. (recommend to be moved to Attachment 2)

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

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted from this version of the NERC standard. Please see the mapped document to see which requirements were moved to NAESB and what future changes are expected. Appendices B, D, G, and the sub-priority portions of E-2 have been moved to NAESB. The appendices below (A, C, E, F) will be renumbered in the final standard.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.
Appendix E. How the IDC Handles Reallocation.
   Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.
   Section E2: Timing Requirements.
Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.
Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.
Appendix C. Sample NERC Transmission Loading Relief Procedure Log

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

<table>
<thead>
<tr>
<th>INCIDENT</th>
<th>DATE</th>
<th>IMPACTED RELIABILITY COORDINATOR</th>
<th>ID NO.</th>
</tr>
</thead>
</table>

INITIAL CONDITIONS

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

TLR Levels

<table>
<thead>
<tr>
<th>TLR Levels</th>
<th>Priorities</th>
</tr>
</thead>
<tbody>
<tr>
<td>0: TLR Incident Canceled</td>
<td>NX Next Hour Market Service</td>
</tr>
<tr>
<td>1. Notify Reliability Coordinators of potential problems.</td>
<td>NS Service over secondary receipt and delivery points</td>
</tr>
<tr>
<td>2: Halt additional transactions that contribute to the overload</td>
<td>ND Daily Service</td>
</tr>
<tr>
<td>3a and 3b: Curtail transactions using Non-firm Transmission Service</td>
<td>NW Weekly Service</td>
</tr>
<tr>
<td>4. Reconfigure to continue firm transactions if needed.</td>
<td>NM Monthly Service</td>
</tr>
<tr>
<td>5a and 5b: Curtail Transactions using Firm Transmission Service.</td>
<td>NN Non-firm imports for native load and network customers from</td>
</tr>
<tr>
<td>6: Implement emergency procedures.</td>
<td>non-designated network resources</td>
</tr>
<tr>
<td>F Firm Service</td>
<td></td>
</tr>
</tbody>
</table>

TLR ACTIONS

<table>
<thead>
<tr>
<th>LEVEL</th>
<th>TIME</th>
<th>Priority</th>
<th>TLR 3, $</th>
<th>MW Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>No. TX Curtail</td>
<td></td>
</tr>
</tbody>
</table>

COMMENTS ABOUT ACTIONS

SAVE FILE DIRECTORY:
NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG
FILE SAVED AS: .XLS
Appendix E. How the IDC Handles Reallocation

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

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

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

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

**Information posted from IDC to NERC TLR website.**

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

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

3. Lowest priority of Interchange Transactions (marginal “bucket”) to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

**IDC Logic, IDC Report, and Timing**

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. Interchange Transactions in restricted directions that are not indicated as “PROCEED” on the Reload/Reallocation Report will not be permitted to start or increase next hour.
Reloading/Reallocation Transaction Status

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

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

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

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

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, “Principles for Mitigating Constraints On and Off the Contract Path.” This is called the “Constrained Path Method,” or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange
Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

**Total Flow Value on a Constrained Facility for Next Hour**

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

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

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.
E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement
1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a reallocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.

2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction subpriorities for Reallocation/Reloading purposes (see Subpriority Table, in the IDC Calculations and Reporting section below).

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

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

<table>
<thead>
<tr>
<th>Example 1</th>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
<td></td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-100 MW</td>
<td></td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>850 MW</td>
<td></td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>850 MW – 800 MW = 50 MW</td>
<td></td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 50 MW = 900 MW</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Example 2</th>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
<td></td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>50 MW</td>
<td></td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>1000 MW</td>
<td></td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>1000 MW – 800 MW = 200 MW</td>
<td></td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 200 MW = 750 MW</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Example 3</th>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
<td></td>
</tr>
<tr>
<td>to-Point Transmission Service</td>
<td></td>
<td></td>
</tr>
<tr>
<td>-----------------------------</td>
<td>----------------------</td>
<td></td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-200 MW</td>
<td></td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>750 MW</td>
<td></td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>750 MW – 800 MW = -50 MW</td>
<td></td>
</tr>
<tr>
<td></td>
<td>None are held</td>
<td></td>
</tr>
</tbody>
</table>

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

**IDC Calculations and Reporting**

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

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

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

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

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

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

**CURTAILED:** The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).
HOLD: The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

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

Tag Reloading for TLR Levels 1 and 0
When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming
Those Interchange Transactions that are at or above the Curtailment Threshold and are not candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment
The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.

2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.

3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.
Special Tag Status

There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.
Example 1 – Transaction curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>20 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>40 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to current hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Load to next hour Energy Profile</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 2 – Transaction curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW, so no change in MW value</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Maintain current flow (not curtailed)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 40MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>40 MW (no curtailment)</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Reduce flow to next-hour Energy Profile (20MW)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 5 — TLR Issued before Transaction was scheduled to start

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td>+0</td>
<td>Tag submitted prior to TLR</td>
</tr>
</tbody>
</table>
Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

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

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

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.

At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

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

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

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

Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.
Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.

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

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.

Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).
Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.

If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.
Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.

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

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.
Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.

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

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.
A. Introduction

1. Title: Reliability Coordination — Transmission Loading Relief (TLR)
2. Number: IRO-006-4
3. Purpose: The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.

4. Applicability:
   4.1. Reliability Coordinators.
   4.2. Transmission Operators.
   4.3. Balancing Authorities.

5. Proposed Effective Date: First day of first quarter after BOT adoption.

B. Requirements

R1. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a “local” (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation due to the time required to implement the procedure. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.


R1.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/mktrules/protocols/current.html

R2. The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing
the potential or actual SOL or IROL violation is a party. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

R3. Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall obtain prior approval of the local procedure from the ERO. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

R4. When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R5. During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

C. Measures

M1. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that demonstrate when Eastern Interconnection, WECC, or ERCOT Interconnection-wide transmission loading relief procedures are implemented, the implementation follows the respective established procedure as specified in this standard (R1, R1.1, R1.2 and R1.3).

M2. Each Reliability Coordinator shall be capable of providing evidence (such as written documentation) that the Transmission Operator experiencing the potential or existing SOL or IROL violations is a party to the local transmission loading relief or congestion management procedures when these procedures have been implemented (R2).

M3. Each Reliability Coordinator shall be capable of providing evidence (such as NERC meeting minutes) that the local procedure has received prior approval by the ERO when such procedure is used as a substitute for curtailment as directed by the Interconnection-wide procedure (R3).

M4. Each Reliability Coordinator shall be capable of providing evidence (such as logs) that the responding Reliability Coordinator complied with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator when requested to curtail an Interchange Transaction that crosses an Interconnection boundary (R4).

M5. Each Reliability Coordinator and Balancing Authority shall be capable of providing evidence (such as Interchange Transaction Tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts) that they have complied with applicable Interchange scheduling standards INT-001, INT-
003, and INT-004 during the implementation of relief procedures, up to the point emergency action is necessary (R5).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

The Reliability Coordinator shall maintain evidence for eighteen months for M1, M4, and M5.

The Reliability Coordinator shall maintain evidence for the duration the Transmission Operator is party to the procedure in effect plus one calendar year thereafter for M2.

The Reliability Coordinator shall maintain evidence for the approved duration of the procedure in effect plus one calendar year thereafter for M3.

1.4. Additional Compliance Information

Each Reliability Coordinator and Balancing Authority shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually and reporting by exception. The Compliance Monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

Each Reliability Coordinator and Balancing Authority shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within 5 days of a request as part of an investigation upon complaint:

1.4.1 Operations logs, voice recordings or transcripts of voice recordings or other documentation providing the evidence of its compliance to all the requirements for all Interconnection-wide TLR procedures that it has implemented during the review period.

1.4.2 TLR reports.

2. Violation Severity Levels

2.1. Lower. There shall be a lower violation severity level if any of the following conditions exist:

2.1.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates one (1) requirement of the applicable Interconnection-wide procedure (R1)
2.1.2 The Reliability Coordinators or Balancing Authorities did not comply with applicable Interchange scheduling standards during the implementation of the relief procedures, up to the point emergency action is necessary (R5).

2.1.3 When requested to curtail an Interchange Transaction that crosses an Interconnection boundary utilizing an Interconnection-wide procedure, the responding Reliability Coordinator did not comply with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator (R4).

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

2.2.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated two (2) to three (3) requirements of the applicable Interconnection-wide procedure (R1).

2.3. **High.** There shall be a high violation severity level if any of the following conditions exist:

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

2.4. **Severe.** There shall be a severe violation severity level if any of the following conditions exist:

2.4.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violated six (6) or more of the requirements of the applicable Interconnection-wide procedure (R1).

2.4.2 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures to relieve congestion but the Transmission Operator experiencing the congestion was not a party to those procedures (R2).

2.4.3 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures as a substitute for curtailment as directed by the Interconnection-wide procedure but the local procedure had not received prior approval from the ERO (R3).

2.4.4 While attempting to mitigate an existing IROL violation in the Eastern Interconnection, the Reliability Coordinator applied TLR as the sole remedy for an existing IROL violation.

2.4.5 While attempting to mitigate an existing constraint in the Western Interconnection using the “WSCC Unscheduled Flow Mitigation Plan”, the Reliability Coordinator did not follow the procedure correctly.

2.4.6 While attempting to mitigate an existing constraint in ERCOT using Section 7 of the ERCOT Protocols, the Reliability Coordinator did not follow the procedure correctly.
E. Regional Differences

1. **PJM/MISO Enhanced Congestion Management**
   (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004. To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

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

   This regional difference impacts actions on behalf of those SPP Balancing Authorities that are participating in the SPP market. This regional difference does not impact those Balancing Authorities for which SPP will continue to act as the Reliability Coordinator but that are not participating in the SPP market.

   SPP shall calculate the impacts of SPP market flow on all facilities included in SPP’s Coordinated Flowgate List. SPP shall conduct sensitivity studies to determine which external flowgates (outside SPP’s footprint) are significantly impacted by the market flows of SPP’s control zones (currently the balancing areas that exist today in the IDC). SPP shall perform studies to determine which external flowgates SPP will monitor and help control. An external flowgate selected by one of the studies will be considered a Coordinated Flowgate (CF).

   In its calculation, SPP shall consider market flow impacts as the impacts of energy dispatched by the SPP market and self-dispatched energy serving load in the market footprint, but not tagged. SPP shall use a method equivalent to the PJM/MISO Market Flow Calculation methodology identified in the PJM/MISO waiver. Impacts of tagged transactions representing delivery of energy not dispatched by the SPP market and energy dispatched by the market but delivered outside the footprint will not be included in market flow.

   SPP shall separate the market flow impacts for current hour and next hour into their appropriate priorities and shall provide those market flow impacts to the IDC. The market flows will be represented in the IDC and made available for curtailment under the appropriate TLR Levels. The market flow impacts will not be represented by conventional interchange transaction tags.

   The SPP method will impact the following sections of the TLR Procedure:

   **Network and Native Load (NNL) Calculations** — The SPP regional difference modifies Attachment 1-IRO-006-1 Section 5 “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service” within the SPP region.

   Section 5 of Attachment 1-IRO-006-1 requires that the “Per Generator Method without Counter Flow” methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each balancing authority.
SPP shall use a “Market Flow Calculation” methodology to calculate the portion of parallel flows on all facilities included in the RTO’s “Coordinated Flowgate List” due to NI service or service to NL of each balancing authority.

The Market Flow Calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar to the “Per Generator Method” method, while providing increased Interchange Distribution Calculator (IDC) granularity. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of other Balancing Authorities for the purposes of identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

**Pro Rata Curtailment of Non-Firm Market Flow Impacts** — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix B “Transaction Curtailment Formula” within the SPP region.

Appendix B “Transaction Curtailment Formula” details the formula used to apply a weighted impact to each non-firm tagged Interchange Transaction (Priorities 1 thru 6) for the purposes of Curtailment by the IDC. For the purpose of Curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by SPP should be curtailed pro-rata as is done for Interchange Transaction using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC are to be curtailed pro rata, the impacting non-firm tagged Interchange Transactions could still use the existing processes to assign the weighted impact value.

**Assignment of Sub-Priorities** — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix E “How the IDC Handles Reallocation”, Section E2 “Timing Requirements”, within the SPP region.

Under the header “IDC Calculations and Reporting” in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: “In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.</td>
<td>The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the lesser of its current-hour MW amount or next-hour schedule in accordance with its energy profile.</td>
<td>The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.</td>
<td>The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S4</td>
<td>To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared</td>
<td>The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same...</td>
</tr>
</tbody>
</table>
to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.) priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

SPP shall use a “Market Flow Calculation” methodology to calculate the amount of energy flowing across all facilities included in the RTO’s “Coordinated Flowgate List” that is associated with the operation of the SPP market. This energy is identified as “market flow.”

These market flow impacts for current hour and next hour will be separated into their appropriate priorities and provided to the IDC by SPP. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional “tags,” the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, for the purposes of reallocation, a sub-priority (S1 thru S4) should be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions.

<table>
<thead>
<tr>
<th>Priority</th>
<th>Purpose</th>
<th>Explanation and Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>To allow existing market flow to maintain or reduce its current MW amount.</td>
<td>The currently flowing MW amount is the amount of market flow existing after the RTO has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead.</td>
</tr>
<tr>
<td>S2</td>
<td>To allow market flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour.</td>
<td>This is the difference between the current hour unconstrained market flow and the current market flow. If the current-hour unconstrained market flow is not available, the IDC will use the most recent market flow since the TLR was first issued or, if not available, the market flow at the time the TLR was first issued.</td>
</tr>
<tr>
<td>S3</td>
<td>To allow a market flow to increase to its next-hour desired amount.</td>
<td>This is the difference between the next hour and current hour unconstrained market flow.</td>
</tr>
</tbody>
</table>

To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.
F. Associated Documents

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
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<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
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<td>0</td>
<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
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<tr>
<td>1</td>
<td>August 8, 2005</td>
<td>Revised Attachment 1</td>
<td>Revision</td>
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<tr>
<td>3</td>
<td>February 26, 2007</td>
<td>Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure</td>
<td>Revision</td>
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<tr>
<td>4</td>
<td>October 23, 2007</td>
<td>Approved by Board of Trustees</td>
<td>Revision</td>
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</tbody>
</table>
PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted. Please see the mapped document to see which items were move to NAESB and what future changes are expected.

Attachment 1 — IRO-006

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

This standard defines procedures for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator.

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

1.1. Initiation only by Reliability Coordinator. A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure.

1.1.1. Requesting relief on transmission facilities. Any Transmission Operator may request from its Reliability Coordinator relief on the transmission facilities it operates. A Reliability Coordinator shall review these requests for relief and determine the appropriate relief actions.

1.2. Mitigating SOL and IROL violations. A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent or mitigate Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. However, the TLR procedure is an inappropriate and ineffective tool as a sole means to mitigate existing IROL violations due to the time required to implement the procedure. Reconfiguration, redispatch, and load shedding are more timely and effective in mitigating existing IROL violations.

1.3. Sequencing of TLR Levels and taking emergency action. The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical sequence (Section 2, “TLR Levels”). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.

1.4. Notification of TLR Procedure implementation. The Reliability Coordinator initiating the use of the TLR

The flexibility for ISOs and RTOs to use redispatch is contained explicitly in the NAESB business practice Section 1.3.
Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

1.4.1. **Notifying other Reliability Coordinators.** The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.

**Actions expected.** The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.

1.4.2. **Notifying Transmission Operators and Balancing Authorities.** The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.

1.4.3. **Notifying Sink Balancing Authorities.** The Reliability Coordinator for the sink Balancing Authority shall be responsible for directing the Sink Balancing Authority to curtail the Interchange Transactions as specified by the Reliability Coordinator implementing the TLR Procedure.

**Notification order.** Within a Transmission Service Priority level, the Sink Balancing Authorities whose Interchange Transactions have the largest impact on the Constrained Facilities shall be notified first if practicable.

1.4.4. **Updates.** At least once each hour, or when conditions change, the Reliability Coordinator implementing the TLR Procedure shall update all other Reliability Coordinators (via the RCIS). Transmission Operators and Balancing Authorities who have had Interchange Transactions impacted by the TLR will be updated by their Reliability Coordinator.

1.5. **Obligations.** All Reliability Coordinators shall comply with the request of the Reliability Coordinator who initiated the TLR Procedure, unless the initiating Reliability Coordinator agrees otherwise.

1.6. **Consideration of Interchange Transactions.** The administration of the TLR Procedure shall be guided by information obtained from the IDC.

1.6.1. **Interchange Transactions not in the IDC.** Reliability Coordinators shall also treat known Interchange Transactions that may not appear in the IDC in accordance with the procedures in this document.

1.6.2. **Transmission elements not in IDC.** When a Reliability Coordinator is faced with an overload on a transmission element that is not modeled in the IDC, the Reliability Coordinator shall use the best information available to curtail Interchange Transactions in order to operate the system in a reliable manner. The Reliability Coordinator shall use its best efforts to ensure that Interchange Transactions with a Transfer Distribution Factor...
of less than the Curtailment Threshold on the transmission element not modeled in the IDC are not curtailed.

1.6.3. **Questionable IDC results.** Any Reliability Coordinator who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:

- Missing Interchange Transactions that are known to contribute to the Constraint.
- Significant change in transmission system topology.
- TDF matrix error.

Impacts of questionable IDC results may include:

- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the Curtailment list are made.

1.6.4. **Curtailment that would cause a constraint elsewhere.** A Reliability Coordinator shall be allowed to exempt an Interchange Transaction from Curtailment if that Reliability Coordinator is aware that the Interchange Transaction Curtailment directed by the IDC would cause a constraint to occur elsewhere. This exemption shall only be allowed after the Reliability Coordinator has consulted with the Reliability Coordinator who initiated the Curtailment.

1.7 **Logging.** The Reliability Coordinator shall complete the NERC Transmission Loading Relief Procedure Log whenever it invokes TLR Level 2 or above, and send a copy of the log via email to NERC within two business days of the TLR event for posting on the NERC website.

1.8 **TLR Event Review.** The Reliability Coordinator shall report the TLR event to the Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

1.8.1 **Providing information.** Transmission Operators and Balancing Authorities within the Reliability Coordinator’s Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.
1.8.2 **Market Committee reviews.** The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

1.8.3 **Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for “lessons learned.”

The Market Committee no longer exists and this requirement will be removed in Phase 3.
2. Transmission Loading Relief (TLR) Levels

Introduction

This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a Reliability Coordinator makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the Interchange Transaction is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. There are further considerations that depend on whether the Constrained Facility is on or off the Contract Path. It is important to note that an Interchange Transaction using Firm Point-to-Point Transmission Service on all Contract Path links is considered a “firm” Interchange Transaction even if the Constrained Facility is off the Contract Path.

2.1. TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

2.1.1. The Reliability Coordinator shall use the following circumstances to establish the need for TLR Level 1:

- The transmission system is secure.
- The Reliability Coordinator foresees a transmission or generation contingency or other operating problem within its Reliability Area that could cause one or more transmission facilities to approach or exceed their SOL or IROL.

2.1.2. Notification procedures. The Reliability Coordinator shall notify all Reliability Coordinators via the Reliability Coordinator Information System (RCIS) as soon as the condition is foreseen. All affected Reliability Coordinators shall check to ensure that Interchange Transactions are posted in the IDC.

2.2. TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations

2.2.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 2:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
2.3 TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b:

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.5 TLR Level 4 — Reconfigure Transmission

2.5.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 4:

- One or more Transmission Facilities are above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken.

2.5.2. Reconfiguration procedures. The issuance of a TLR Level 4 shall result in the curtailment, in the current hour and the next hour, of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold that impact the Constrained
Facilities. If a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint.

2.6. **TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service**

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

2.7. **TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation**

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b:

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.
2.8. **Curtailment of Interchange Transactions Using Firm Transmission Service**

2.8.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

2.8.1.1. **TLR Level 5a.** Enable additional Interchange Transactions using Firm Point-to-Point Transmission Service to be implemented after all Interchange Transactions using Non-firm Point-to-Point Service have been curtailed, or

2.8.1.2. **TLR Level 5b.** Mitigate a SOL or IROL violation that remains after all Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.

2.9. **TLR Level 6 — Emergency Procedures**

2.9.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 6:

- One or more Transmission Facilities are above their SOL or IROL.
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.9.2. **Implementing emergency procedures.** If the Reliability Coordinator deems that transmission loading is critical to Bulk Electric System reliability, the Reliability Coordinator shall immediately direct the Balancing Authorities and Transmission Operators in its Reliability Area to redispach generation, or reconfigure transmission, or reduce load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All Balancing Authorities and Transmission Operators shall comply with all requests from their Reliability Coordinator.

2.10 **TLR Level 0 — TLR concluded**

2.10.1. **Interchange Transaction restoration and notification procedures.** The Reliability Coordinator initiating the TLR Procedure shall notify all Reliability Coordinators within the Interconnection via the RCIS when the SOL or IROL violations are mitigated and the system is in a reliable state, allowing Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. **Requirements**

3.1. The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.
3.2 The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

3.2.1 If issued prior to XX: 25, Non-firm Interchange Transactions will be curtailed to meet the desired current hour relief

4.2.1.1 At XX: 25 a Reallocation will be performed to maintain the desired flow at the top of the following hour

3.2.2 If issued after XX: 25, Non firm Interchange Transactions will be curtailed to meet the desired current hour relief and a Reallocation will be performed to maintain the target flow identified for the current hour.

3.2.3 Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation.

3.3 The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include: (recommended to be moved to Attachment 2)

3.3.1 Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed or held during current and next hours. (recommended to be moved to Attachment 2)

3.3.2 Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after XX:25 or issuance of TLR 3b (see Case 3 in Appendix F). (recommended to be moved to Attachment 2)

3.4 The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called. (recommend to be moved to Attachment 2)

3.5 The Reliability Coordinator will no longer be required to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b. (recommend to be moved to Attachment 2)
Appendices for Transmission Loading Relief Standard

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted from this version of the NERC standard. Please see the mapped document to see which requirements were moved to NAESB and what future changes are expected. Appendices B, D, G, and the sub-priority portions of E-2 have been moved to NAESB. The appendices below (A, C, E, F) will be renumbered in the final standard.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.
Appendix E. How the IDC Handles Reallocation.
    Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.
    Section E2: Timing Requirements.
Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.
Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.
Appendix C. Sample NERC Transmission Loading Relief Procedure Log

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

<table>
<thead>
<tr>
<th>INCIDENT</th>
<th>DATE</th>
<th>IMPACTED RELIABILITY COORDINATOR</th>
<th>ID NO.</th>
</tr>
</thead>
<tbody>
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<td></td>
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<table>
<thead>
<tr>
<th>INITIAL CONDITIONS</th>
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<tbody>
<tr>
<td>Limiting Flowgate (LIMIT) Rating Contingent Flowgate (CONT.) ODF</td>
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</table>

<table>
<thead>
<tr>
<th>TLR Levels</th>
<th>Priorities</th>
</tr>
</thead>
<tbody>
<tr>
<td>0: TLR Incident Canceled</td>
<td>NX Next Hour Market Service</td>
</tr>
<tr>
<td>1. Notify Reliability Coordinators of potential problems.</td>
<td>NS Service over secondary receipt and delivery points</td>
</tr>
<tr>
<td>2: Halt additional transactions that contribute to the overload</td>
<td>ND Daily Service</td>
</tr>
<tr>
<td>3a and 3b: Curtail transactions using Non-firm Transmission Service</td>
<td>NW Weekly Service</td>
</tr>
<tr>
<td>4. Reconfigure to continue firm transactions if needed</td>
<td>NM Monthly Service</td>
</tr>
<tr>
<td>5a and 5b: Curtail Transactions using Firm Transmission Service</td>
<td>NN Non-firm imports for native load and network customers from non-designated network resources</td>
</tr>
<tr>
<td>6: Implement emergency procedures.</td>
<td>F Firm Service</td>
</tr>
</tbody>
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</tbody>
</table>
Appendix E. How the IDC Handles Reallocation

The IDC algorithms reflect the Reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority and post the Reloading/Reallocation information to the NERC TLR website.

A summary of IDC features that support the Reallocation process is provided in Attachment E1. Details on the interface and display features are provided in Attachment E2. Refer to Version 1.7.095 NERC Transaction Information Systems Working Group (TISWG) Electronic Tagging Functional Specification for details about the E-Tag system.

E1. Summary of IDC Features that Support Transaction Reloading/Reallocation

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.

2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.

3. Lowest priority of Interchange Transactions (marginal “bucket”) to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. Interchange Transactions in restricted directions that are not indicated as “PROCEED” on the Reload/Reallocation Report will not be permitted to start or increase next hour.
Reloading/Reallocation Transaction Status

Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.

1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase. Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

2. **CURTAILED.** Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. Interchange Transactions (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The Balancing Authority will indicate to the IDC through the E-Tag adjustment table the Interchange Transaction’s curtailed values.

3. **PROCEED:** Interchange Transaction is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The Balancing Authority will indicate through the E-Tag adjustment table to IDC if Interchange Transaction will reload, start, or increase next-hour per Purchasing-Selling Entity’s energy schedule as appropriate.

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, “Principles for Mitigating Constraints On and Off the Contract Path.” This is called the “Constrained Path Method,” or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocating the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange
Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

**Total Flow Value on a Constrained Facility for Next Hour**

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:

   - Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,
   - SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and
   - Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.
E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.

2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the IDC Calculations and Reporting section below).

Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing Reliability Coordinator (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the Reliability Coordinator to Reallocate or reload currently halted or curtailed Interchange Transactions next hour. The reminder will be in the form of an alarm to the issuing Reliability Coordinator, and will take place at 00:25 so that, if the Reliability Coordinator re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the approved tag submission deadline for Reallocation are available in the IDC.

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions...
for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the “delta incremental flow:”

**Example 1**

<table>
<thead>
<tr>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-100 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>850 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>850 MW – 800 MW = 50 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 50 MW = 900 MW</td>
</tr>
</tbody>
</table>

**Example 2**

<table>
<thead>
<tr>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
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</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>50 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>1000 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>1000 MW – 800 MW = 200 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW – 200 MW = 750 MW</td>
</tr>
</tbody>
</table>

**Example 3**

<table>
<thead>
<tr>
<th>Flow to maintain on Facility</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
</tbody>
</table>
### to-Point Transmission Service

| Contribution from flow next hour from service to Network customers and Native Load | -200 MW |
| Expected Net flow next hour on Facility | 750 MW |
| Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation | 750 MW – 800 MW = -50 MW None are held |

For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

### IDC Calculations and Reporting

At the time the TLR report is processed, the IDC will use all candidate Interchange Transactions for Reallocation that met the approved tag submission deadline for Reallocation plus those Interchange Transactions that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an Interchange Transactions Halt/Curtailment list that will include reload and Reallocation of Interchange Transactions. The Interchange Transactions are prioritized as follows:

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0 (Recommended to be placed in Attachment 2).

   Examples of Interchange Transactions using Non-firm Transmission Service sub-priority settings begin in the **Transaction Sub-priority Examples** following sections

2. All Interchange Transactions using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all Interchange Transactions using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All Interchange Transactions processed in a TLR are assigned one of the following statuses:

**PROCEED:** The Interchange Transaction has started or is allowed to start to the next hour MW schedule amount.

**CURTAILED:** The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).
HOLD: The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

Upon acceptance of the TLR Transaction Reallocation/reloading report by the issuing Reliability Coordinator, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each Interchange Transaction in the IDC TLR report. The Interchange Transaction will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/Reallocation report will be made available at NERC’s public TLR website, and it is NERC’s responsibility to format and publish the report.

**Tag Reloading for TLR Levels 1 and 0**

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

**New Tag Alarming**

Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

**Tag Adjustment**

The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.

2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.

3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.
Special Tag Status
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples
The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.
Example 1 – Transaction curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>20 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>40 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to current hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Load to next hour Energy Profile</td>
</tr>
</tbody>
</table>

TLR
Example 2 – Transaction curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>10 MW</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>10 MW</td>
<td>Maintain current curtailed flow</td>
</tr>
<tr>
<td>S2</td>
<td>+10 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW, so no change in MW value</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Maintain current flow (not curtailed)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 40MW</td>
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<tr>
<td>S4</td>
<td></td>
<td></td>
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</table>
Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

<table>
<thead>
<tr>
<th>Energy Profile: Current hour</th>
<th>40 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual flow following curtailment: Current hour</td>
<td>40 MW (no curtailment)</td>
</tr>
<tr>
<td>Energy Profile: Next hour</td>
<td>20 MW</td>
</tr>
</tbody>
</table>

Sub-priorities for Transaction MW:

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>20 MW</td>
<td>Reduce flow to next-hour Energy Profile (20MW)</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Reload to lesser of current and next-hour Energy Profile</td>
</tr>
<tr>
<td>S3</td>
<td>+0 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Example 5 — TLR Issued before Transaction was scheduled to start

<table>
<thead>
<tr>
<th>Sub-Priority</th>
<th>MW Value</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S2</td>
<td>+0 MW</td>
<td>Transaction was not allowed to start</td>
</tr>
<tr>
<td>S3</td>
<td>+20 MW</td>
<td>Next-hour Energy Profile is 20MW</td>
</tr>
<tr>
<td>S4</td>
<td>+0</td>
<td>Tag submitted prior to TLR</td>
</tr>
</tbody>
</table>

#### Energy Profile:
- **Current hour:** 0 MW
- **Next hour:** 20 MW

#### Actual flow following curtailment:
- **Current hour:** 0 MW (Transaction scheduled to start *after* TLR initiated)
Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.
Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.

Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.
Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.

The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.

All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.

Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.

Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).
Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.

If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.
Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.

Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.
Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.

Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.
Standard Development Roadmap
This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

<table>
<thead>
<tr>
<th>Completed Actions</th>
<th>Completion Date</th>
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</thead>
<tbody>
<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 21, 2007</td>
</tr>
<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 30, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 17, 2008</td>
</tr>
<tr>
<td>5. Post Draft Standard for Operating Committee approval</td>
<td>January 17, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
</tr>
</tbody>
</table>

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for IRO-STD-006-0. IRO-006-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when IRO-STD-006-0 was approved as a NERC reliability standard. A white paper is attached to explain the refinements in this reliability standard.

This posting of the standard is for WECC Board of Directors ballot. The Operating Committee recommends that the WECC Board of Directors approve the IRO-006-WECC-1 as a permanent replacement standard for IRO-STD-006-0 and that the WSCC Board of Directors submit the standard to NERC and FERC for approval.

Future Development Plan:

<table>
<thead>
<tr>
<th>Anticipated Actions</th>
<th>Anticipated Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. WECC Board ballots proposed standard</td>
<td>April 16-18, 2008</td>
</tr>
<tr>
<td>3. Drafting Team to review and respond to industry comments</td>
<td>May 2008</td>
</tr>
<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
</tr>
<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
</tr>
</tbody>
</table>
Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

DEFINITIONS:

Contributing Schedule is defined as a Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.

Qualified Transfer Path: A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.

Qualified Controllable Device: A controllable device installed in the Interconnection for controlling energy flow, and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Qualified Transfer Path Curtailment Event: Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (see Attachment 1-IRO-006-WECC-1) during which the curtailment tool is functional.

Transfer Distribution Factor (TDF): The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]

Relief Requirement: The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority’s Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
A. Introduction

1. Title: Qualified Transfer Path Unscheduled Flow (USF) Relief
2. Number: IRO-006-WECC-1
3. Purpose: Mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths.

4. Applicability
   4.1. Balancing Authorities
   4.2. Reliability Coordinators

5. Effective Date: The first day of the first quarter after applicable regulatory approvals.

B. Requirements

   R.1. Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the Reliability Coordinator shall approve (actively or passively) or deny that request within five minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

   R.2. The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination thereof that collectively meets the Relief Requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

   M1. The Reliability Coordinator shall have evidence that it approved or denied the request within five minutes in accordance with R1.

   M2. The Balancing Authorities shall have evidence that they provided the Relief Requirement through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in R.2.

D. Compliance

1. Compliance Monitoring Process
   1.1 Compliance Monitoring Responsibility
      Compliance Enforcement Authority
   1.2. Compliance Monitoring Period and Reset
      Compliance Enforcement Authority may use one or more of the following methods to assess compliance:
- Reviews conducted monthly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 Compliance Monitoring Period: A Qualified Transfer Path Curtailment Event

1.2.2 The Performance-reset Period is one calendar month.

1.3. Data Retention

Reliability Coordinators and Balancing Authorities shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.

2. Violation Severity Levels of Non-Compliance for Requirement R1

2.1. Lower: There shall be a Lower Level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a Step 4 or greater request greater than five minutes after receipt of notification from the Transmission Operator of a Qualified Transfer Path.

2.2. Moderate: Not Applicable

2.3. High: Not Applicable

2.4. Severe: Not Applicable

3. Violation Severity Levels of Non-Compliance for Requirement R2

2.1. Lower: There shall be a Lower Level of non-compliance if there is less than 100% Relief Requirement provided but greater than or equal to 90% Relief Requirement provided or the Relief Requirement was less than 5 MW and was not provided.

2.2. Moderate: There shall be a Moderate Level of non-compliance if there is less than 90% Relief Requirement provided but greater than or equal to 75% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

2.3. High: There shall be a High Level of non-compliance if there is less than 75% Relief Requirement provided but greater than or equal to 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

2.4. Severe: There shall be a Severe Level of non-compliance if there is less than 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.
### Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>January 1, 2008</td>
<td>Permanent Replacement Standard for IRO-STD-006-0</td>
<td></td>
</tr>
</tbody>
</table>
### Attachment 1 WECC IRO-006-WECC-1
WECC UNSCHEDULED FLOW MITIGATION
SUMMARY OF ACTIONS

<table>
<thead>
<tr>
<th>Step</th>
<th>Action Description</th>
<th>Unscheduled Flow Accommodation across Path</th>
<th>Equivalent Percent Curtailment Required in Contributing Schedule -Based on amount of Unscheduled Flow across the Qualified Transfer Path</th>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>(Transfer Distribution Factor)</strong></td>
</tr>
<tr>
<td>1</td>
<td>Operate controllable devices in path</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Accommodation</td>
<td>50 MW or 5% of maximum transfer limit</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Coordinated operation of Qualified Controllable Devices</td>
<td>50 MW or /5% of maximum transfer limit</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>First level curtailment</td>
<td>50 MW or 5% of maximum transfer limit</td>
<td>10% 20%</td>
</tr>
<tr>
<td>5</td>
<td>Second level curtailment</td>
<td>50 MW or 5% of maximum transfer limit</td>
<td>10% 15% 25%</td>
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<tr>
<td>6</td>
<td>Accommodation</td>
<td>75 MW or 6% of maximum transfer limit</td>
<td>10% 15% 25%</td>
</tr>
<tr>
<td>7</td>
<td>Third level curtailment</td>
<td>75 MW or 6% of maximum transfer limit</td>
<td>10% 15% 20% 30%</td>
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<tr>
<td>8</td>
<td>Accommodation</td>
<td>100 MW or 7% of maximum transfer limit</td>
<td>10% 15% 20% 30%</td>
</tr>
<tr>
<td>9</td>
<td>Fourth level curtailment</td>
<td>100 MW or 7% of maximum transfer limit</td>
<td>10% 15% 20% 25% 35%</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Reliability Coordinator Operational Analyses and Real-time Assessments

2. Number: IRO-008-1

3. Purpose: To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring that the Bulk Electric System is assessed during the operations horizon.

4. Applicability

   4.1. Reliability Coordinator.

5. Proposed Effective Date:

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. (Violation Risk Factor: Medium) (Time Horizon: Operations Planning)

R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. (Violation Risk Factor: High) (Time Horizon: Real-time Operations)

R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. (Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)

C. Measures

M1. The Reliability Coordinator shall have, and make available upon request, the results of its Operational Planning Analyses.

M2. The Reliability Coordinator shall have, and make available upon request, evidence to show it conducted a Real-Time Assessment at least once every 30 minutes. This evidence could include, but is not limited to, dated computer log showing times the assessment was conducted, dated checklists, or other evidence.
M3. The Reliability Coordinator shall have and make available upon request, evidence to confirm that it shared the results of its Operational Planning Analyses or Real-Time Assessments with those entities expected to take actions based on that information. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated transcripts of voice records, dated facsimiles, or other evidence.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For Reliability Coordinators that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

The Reliability Coordinator shall retain evidence for Requirement R1, Measure M1 and Requirement R2, Measure M2 for a rolling 30 days. The Reliability Coordinator shall keep evidence for Requirement R3, Measure M3 for a rolling three months.

1.5. Additional Compliance Information

None.
## 2. Violation Severity Levels

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<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1</strong></td>
<td>Performed an Operational Planning Analysis that covers all aspects of the requirement for all except one of 30 days. (R1)</td>
<td>Performed an Operational Planning Analysis that covers all aspects of the requirement for all except two of 30 days. (R1)</td>
<td>Performed an Operational Planning Analysis that covers all aspects of the requirement for all except three of 30 days. (R1)</td>
<td>Missed performing an Operational Planning Analysis that covers all aspects of the requirement for four or more of 30 days. (R1)</td>
</tr>
<tr>
<td><strong>R2</strong></td>
<td>For any sample 24 hour period within the 30 day retention period, a Real-time Assessment was not conducted for one 30-minute period. within that 24-hour period (R2)</td>
<td>For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for two 30-minute periods within that 24-hour period (R2)</td>
<td>For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for three 30-minute periods within that 24-hour period (R2)</td>
<td>For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for more than three 30-minute periods within that 24-hour period (R2)</td>
</tr>
<tr>
<td><strong>R3</strong></td>
<td></td>
<td>Shared the results with some but not all of the entities that were required to take action (R3)</td>
<td></td>
<td>Did not share the results of its analyses or assessments with any of the entities that were required to take action (R3).</td>
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</tbody>
</table>
E. Regional Variances

None

F. Associated Documents

None

Version History

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</tr>
</tbody>
</table>
A. Introduction

1. **Title:** Reliability Coordinator Actions to Operate Within IROLs

2. **Number:** IRO-009-1

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).

4. **Applicability:**

   4.1 Reliability Coordinator.

5. **Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

**R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

**R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL’s T_v. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

**R3.** When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Reliability Coordinator shall implement one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) to prevent exceeding that IROL. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

**R4.** When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL’s T_v. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*
R5. If unanimity cannot be reached on the value for an IROL or its $T_v$, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

C. Measures

M1. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it has Operating Processes, Procedures, or Plans to address both preventing and mitigating instances of exceeding IROLs in accordance with Requirement R1 and Requirement R2. This evidence shall include a list of any IROLs (and each associated $T_v$) identified in advance, along with one or more dated Operating Processes, Procedures, or Plans that that will be used.

M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3 and Requirement R4. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

M3. For a situation where Reliability Coordinators disagree on the value of an IROL or its $T_v$, the Reliability Coordinator shall have, and make available upon request, evidence to confirm that it used the most conservative of the values under consideration, without delay. Such evidence could include, but is not limited to, dated computer printouts, dated operator logs, dated voice recordings, dated transcripts of voice recordings, or other equivalent evidence. *(R5)*

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For Reliability Coordinators that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
Exception Reporting

1.4. **Data Retention**

The Reliability Coordinator, shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator shall retain evidence of Requirement R1, Requirement R2, and Measure M1, for a rolling 12 months.

- The Reliability Coordinator shall retain evidence of Requirement R3, Requirement R4, Requirement R5, Measure M2, and Measure M3 for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and all IROL Violation Reports submitted since the last audit.

1.5. **Additional Compliance Information**

**Exception Reporting:** For each instance of exceeding an IROL for time greater than IROL T_v, the Reliability Coordinator shall submit an IROL Violation Report to its Compliance Enforcement Authority within 30 days of the initiation of the event.
2. Violation Severity Levels

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
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<tbody>
<tr>
<td>R1</td>
<td></td>
<td></td>
<td></td>
<td>An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL. (R1)</td>
</tr>
<tr>
<td>R2</td>
<td></td>
<td></td>
<td></td>
<td>An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL’s Tₜ. (R2)</td>
</tr>
<tr>
<td>R3</td>
<td></td>
<td></td>
<td></td>
<td>An assessment of actual or expected system conditions predicted that an IROL in the Reliability Coordinator’s Area would be exceeded, but no Operating Processes, Procedures, or Plans were implemented. (R3)</td>
</tr>
<tr>
<td>R4</td>
<td></td>
<td></td>
<td></td>
<td>Actual system conditions</td>
</tr>
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Adopted by NERC Board of Trustees: October 17, 2008
<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
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<th>Severe</th>
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<tbody>
<tr>
<td></td>
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<td></td>
<td>showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and there was a delay of five minutes or more before acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding that IROL, however the IROL was mitigated within the IROL’s $T_v$. (R4)</td>
<td>showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and that IROL was not resolved within the IROL’s $T_v$. (R4)</td>
</tr>
<tr>
<td>R5</td>
<td>Not applicable.</td>
<td>Not applicable.</td>
<td>Not applicable.</td>
<td>There was a disagreement on the value of the IROL or its $T_v$, and the most conservative limit under consideration was not used. (R5)</td>
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E. Regional Variances

None

F. Associated Documents

IROL Violation Report

Version History

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</tbody>
</table>
A. Introduction

1. Title: Reliability Coordinator Data Specification and Collection
2. Number: IRO-010-1
3. Purpose: To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

4. Applicability

4.1. Reliability Coordinator.
4.2. Balancing Authority.
4.3. Generator Owner.
4.4. Generator Operator.
4.5. Interchange Authority.
4.8. Transmission Owner.

5. Proposed Effective Date:

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

R1.2. Mutually agreeable format.

R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).
R1.4. Process for data provision when automated Real-Time system operating data is unavailable.

R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning; Same-day Operations; Real-time Operations)*

C. Measures

M1. The Reliability Coordinator shall have, and make available upon request, a documented data specification that contains all elements identified in Requirement R1.

M2. The Reliability Coordinator shall have, and make available upon request, evidence that it distributed its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. This evidence could include, but is not limited to, dated paper or electronic notice used to distribute its data specification showing recipient, and data or information requested or other equivalent evidence. *(R2)*

M3. The Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall each have, and make available upon request, evidence to confirm that it provided data and information, as specified in Requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated computer printouts, dated SCADA data, or other equivalent evidence.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

   For Reliability Coordinators and other functional entities that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

   For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

   1.2. Compliance Monitoring Period and Reset Time Frame

   Not applicable.

   1.3. Compliance Monitoring and Enforcement Processes

   Compliance Audits

   Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

The Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner, shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force data specification for Requirement R1, Measure M1.

The Reliability Coordinator shall keep evidence of its most recent distribution of its data specification and evidence to show the data supplied in response to that specification for Requirement R2, Measure M2 and Requirement R3 Measure M3.

For data that is requested in accordance with Requirement R2, the Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall keep evidence used to show compliance with Requirement R3 Measure M3 for the Reliability Coordinator’s most recent data specification for a rolling 90 calendar days.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.
2. **Violation Severity Levels**

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1</strong></td>
<td>Data specification is complete with the following exception: Missing the mutually agreeable format. (R1.2)</td>
<td>Data specification is complete with the following exception – no process for data provision when automated Real-Time system operating data is unavailable. (R1.4)</td>
<td>Data specification incomplete (missing either the list of required data (R1.1), or the timeframe for providing data. (R1.3)</td>
<td>No data specification (R1)</td>
</tr>
<tr>
<td><strong>R2</strong></td>
<td>Distributed its data specification to greater than or equal to 95% but less than 100% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status.</td>
<td>Distributed its data specification to greater than or equal to 85% but less than 95% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
<td>Distributed its data specification to greater than or equal to 75% - but less than 85% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
<td>Data specification distributed to less than 75% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
</tr>
<tr>
<td><strong>R3</strong></td>
<td>Provided greater than or equal to 95% but less then 100% of the data and information as specified. (R3)</td>
<td>Provided greater than or equal to 85% but less than 95% of the data and information as specified. (R3)</td>
<td>Provided greater than or equal to 75% but less then 85% of the data and information as specified. (R3)</td>
<td>Provided less than 75% of the data and information as specified. (R3)</td>
</tr>
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E. Regional Variances
   None

F. Associated Documents
   None

Version History

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</table>
A. Introduction

1. Title: Reliability Coordinator Data Specification and Collection
2. Number: IRO-010-1a
3. Purpose: To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

4. Applicability
   4.1. Reliability Coordinator.
   4.2. Balancing Authority.
   4.3. Generator Owner.
   4.4. Generator Operator.
   4.5. Interchange Authority.
   4.8. Transmission Owner.

5. Proposed Effective Date: In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

   R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

   R1.2. Mutually agreeable format.

   R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).

   R1.4. Process for data provision when automated Real-Time system operating data is unavailable.
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning; Same-day Operations; Real-time Operations)*

C. Measures

M1. The Reliability Coordinator shall have, and make available upon request, a documented data specification that contains all elements identified in Requirement R1.

M2. The Reliability Coordinator shall have, and make available upon request, evidence that it distributed its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. This evidence could include, but is not limited to, dated paper or electronic notice used to distribute its data specification showing recipient, and data or information requested or other equivalent evidence. *(R2)*

M3. The Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall each have, and make available upon request, evidence to confirm that it provided data and information, as specified in Requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated computer printouts, dated SCADA data, or other equivalent evidence.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

   For Reliability Coordinators and other functional entities that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

   For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

   1.2. Compliance Monitoring Period and Reset Time Frame

   Not applicable.

   1.3. Compliance Monitoring and Enforcement Processes

   Compliance Audits
   Self-Certifications
   Spot Checking
   Compliance Violation Investigations
Self-Reporting

Complaints

1.4. Data Retention

The Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner, shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force data specification for Requirement R1, Measure M1.

The Reliability Coordinator shall keep evidence of its most recent distribution of its data specification and evidence to show the data supplied in response to that specification for Requirement R2, Measure M2 and Requirement R3 Measure M3.

For data that is requested in accordance with Requirement R2, the Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall keep evidence used to show compliance with Requirement R3 Measure M3 for the Reliability Coordinator’s most recent data specification for a rolling 90 calendar days.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.
### 2. Violation Severity Levels

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>Data specification is complete with the following exception:</td>
<td>Data specification is complete with the following exception –</td>
<td>Data specification incomplete (missing either the list of required data (R1.1), or the timeframe for providing data. (R1.3)</td>
<td>No data specification (R1)</td>
</tr>
<tr>
<td></td>
<td>Missing the mutually agreeable format. (R1.2)</td>
<td>no process for data provision when automated Real-Time system operating data is unavailable. (R1.4)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>R2</td>
<td>Distributed its data specification to greater than or equal to 95% but less than 100% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status.</td>
<td>Distributed its data specification to greater than or equal to 85% but less than 95% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
<td>Distributed its data specification to greater than or equal to 75% - but less then 85% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
<td>Data specification distributed to less than 75% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)</td>
</tr>
<tr>
<td>R3</td>
<td>Provided greater than or equal to 95% but less then 100% of the data and information as specified. (R3)</td>
<td>Provided greater than or equal to 85% but less than 95% of the data and information as specified. (R3)</td>
<td>Provided greater than or equal to 75% but less then 85% of the data and information as specified. (R3)</td>
<td>Provided less than 75% of the data and information as specified. (R3)</td>
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E. Regional Variances

None

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1.2 and R3

Version History

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<td>October 17, 2008</td>
<td>Adopted by Board of Trustees</td>
<td>New</td>
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<tr>
<td>1a</td>
<td>August 5, 2009</td>
<td>Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees</td>
<td>Addition</td>
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Appendix 1

Interpretation of Requirements R1.2 and R3

Text of Requirements R1.2 and R3

| R1. | The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: |
| R1.1. | List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. |
| R1.2. | Mutually agreeable format. |
| R1.3. | Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). |
| R1.4. | Process for data provision when automated Real-Time system operating data is unavailable. |
| R3. | Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship. |

**Question 1**

Does the phrase, “as specified” in Requirement R3 reference the documented data and information specification in IRO-010-1 Requirement R1, or is the data and information in Requirement R3 “any” data and information that the Reliability Coordinator might request?

**Response:** The data to be supplied in Requirement R3 applies to the documented specification for data and information referenced in Requirement R1.

**Question 2**

Is the intent of Requirement R3 to have each responsible entity provide its own data and information to its Reliability Coordinator, or is the intent to have responsible entities provide aggregated data (collected and compiled from other entities at the direction of the Reliability Coordinator) to the Reliability Coordinator?

**Response:** The intent of Requirement R3 is for each responsible entity to ensure that its data and information (as stated in the documented specification in Requirement R1) are provided to the Reliability Coordinator.

Another entity may provide that data or information to the Reliability Coordinator on behalf of the responsible entity, but the responsibility remains with the responsible entity. There is neither intent nor obligation for any entity to compile information from other entities and provide it to the Reliability Coordinator.
**Question 3**

Under Requirement R1.2, what actions (on the part of the Reliability Coordinator) are expected to support the “mutually acceptable format” for submission of data and information?

**Response:** Requirement R1.2 mandates that the parties will reach a mutual agreement with respect to the format of the data and information. If the parties can not mutually agree on the format, it is expected that they will negotiate to reach agreement or enter into dispute resolution to resolve the disagreement.
A. Introduction

1. Title: Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
2. Number: IRO-014-1
3. Purpose: To ensure that each Reliability Coordinator’s operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. Applicability
   4.1. Reliability Coordinator
5. Effective Date: November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.

R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:

   R1.1.1. Communications and notifications, including the conditions\(^1\) under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

   R1.1.2. Energy and capacity shortages.

   R1.1.3. Planned or unplanned outage information.

   R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.

   R1.1.5. Coordination of information exchange to support reliability assessments.

   R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

R2. Each Reliability Coordinator’s Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:

   R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).

   R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).

\(^1\) Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren’t limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of special protection systems, etc.
R3. A Reliability Coordinator’s Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:

R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R3.2. The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

R4.1. Include version control number or date.

R4.2. Include a distribution list.

R4.3. Be reviewed, at least once every three years, and updated if needed.

C. Measures

M1. The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

M1.1 These Operating Procedures, Processes, or Plans shall address:

M1.1.1 Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

M1.1.2 Energy and capacity shortages.

M1.1.3 Planned or unplanned outage information.

M1.1.4 Voltage control, including the coordination of reactive resources for voltage control.

M1.1.5 Coordination of information exchange to support reliability assessments.

M1.1.6 Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

M2.1 Agreed to by all the Reliability Coordinators required to take the indicated action(s).

M2.2 Distributed to all Reliability Coordinators that are required to take the indicated action(s).

M3. The Reliability Coordinator’s Operating Procedures, Processes, or Plans developed (for its System Operators’ internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

M3.1 Be available to the Reliability Coordinator’s System Operators for Real-time use,

M3.2 Include a reference to the associated source document, and

M3.3 Support the agreed-upon actions from the source document.
M4. The Reliability Coordinator’s Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be one calendar year.

   1.3. Data Retention

   The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

   1.4. Additional Compliance Information

   The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction’s discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator’s System Operators.

   The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

   1.4.1 The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

   1.4.2 Evidence of distribution of Operating Procedures, Processes, or Plans.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

   2.1.1 The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

   2.1.2 The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include
both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

2.2. **Level 2:** There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 Documents required by this standard were not distributed to all entities on the distribution list.

2.2.2 Documents required by this standard were not available for System Operators’ Real-time use.

2.2.3 Documents required by this standard do not address all required topics.

2.3. **Level 3:** Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014 R1.

2.4. **Level 4:** Not Applicable.

E. Regional Differences

None Identified.

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A. Introduction

1. Title: Notifications and Information Exchange Between Reliability Coordinators
2. Number: IRO-015-1
3. Purpose: To ensure that each Reliability Coordinator’s operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. Applicability
   4.1. Reliability Coordinators

5. Effective Date: November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.
   R1.1. The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.
   R2.1. The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.

R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.

C. Measures

M1. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) it has followed its Operating Procedures, Processes, or Plans for notifying other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) that it participated in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

M3. The Reliability Coordinator shall have evidence that it provided requested reliability-related information to other Reliability Coordinators.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization
1.2. **Compliance Monitoring Period and Reset Time Frame**

The Performance Reset Period shall be one calendar year.

1.3. **Data Retention**

The Reliability Coordinator shall keep auditable documentation for a rolling 12 months. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance — whichever is longer.

1.4. **Additional Compliance Information**

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction’s discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or an investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been making notifications and exchanging reliability-related information according to agreed Operating Procedures, Processes, or Plans.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five days of a request as part of an investigation upon complaint:

1.4.1 Evidence it has participated in agreed-upon conference calls or other communications forums.

1.4.2 Operating logs or other data sources that document notifications made to other Reliability Coordinators.

2. **Levels of Non-Compliance**

2.1. **Level 1**: Did not participate in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

2.2. **Level 2**: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications but no Adverse Reliability Impacts resulted from the incident.

2.3. **Level 3**: Did not provide requested reliability-related information to other Reliability Coordinators.

2.4. **Level 4**: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications and Adverse Reliability Impacts resulted from the incident.

E. **Regional Differences**

None Identified.

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A. Introduction
1. Title: Coordination of Real-time Activities Between Reliability Coordinators
2. Number: IRO-016-1
3. Purpose: To ensure that each Reliability Coordinator’s operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. Applicability
   4.1. Reliability Coordinator
5. Effective Date: November 1, 2006

B. Requirements
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.
   R1.1. If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.
   R1.2. If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
      R1.2.1. If time permits, this re-evaluation shall be done before taking corrective actions.
      R1.2.2. If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.
   R1.3. If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

C. Measures
M1. For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

D. Compliance
1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization
   1.2. Compliance Monitoring Period and Reset Time Frame
       The performance reset period shall be one calendar year.
1.3. Data Retention

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction’s discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

1.4.1 Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

E. Regional Differences

None identified.

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8. Changed apostrophes to “smart” symbols.
10. Added comma after word “expected” in item 1.4, last sentence.
11. Removed extra spaces between words where appropriate.
A. Introduction

1. Title: Qualified Path Unscheduled Flow Relief
2. Number: IRO-STD-006-0
3. Purpose: Mitigation of transmission overloads due to unscheduled line flow on Qualified Paths.

4. Applicability

4.1. This criterion applies to Transmission Operators, Balancing Authorities and Load Serving Entities within the Western Interconnection.

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1.

Curtailment of Contributing Schedules

WECC’s Unscheduled Flow Mitigation Plan (Plan), which is on file with FERC and has been accepted by FERC (most recently prior to the date hereof on November 20, 2001 in Docket No. ER01-3085-000), 1/ specifies that members 2/ shall comply with requests from (Qualified) Transfer Path Operators to take actions that will reduce unscheduled flow on the Qualified Path in accordance with the table entitled “WECC Unscheduled Flow Procedure Summary of Curtailment Actions,” which is located in Attachment 1 of the Plan.

Plan Section 11:

11.1 When USF Accommodation, as specified in Section 7, together with coordinated operation of the Qualified Controllable Devices, as specified in Section 9, are insufficient to reduce the Actual Flow on the Qualified Transfer Path to below the Transfer Limit, the Transfer Path Operator shall request curtailments in Schedules that contribute to the USF through the Qualified Transfer Path according to the USF Reduction Procedure.

11.2 Responsible Entities shall comply in a timely manner with a Transfer Path Operator's request for Schedule Curtailments.

1/ Capitalized terms used in this section, unless separately defined in this standard, shall have the meaning specified in the Plan.

2/ Reliability Standard will apply to all Responsible Entities within the Western Interconnection.
Plan Attachment 1 Section 9:

“h. Upon receipt of a curtailment request, Contributing Schedules which are subject to curtailments will be reduced (or equivalent alternative schedule adjustments will be effected) in accordance with the following procedures:

i. Receivers of Contributing Schedules will initiate the requested schedule reductions unless an otherwise agreed upon procedure for schedule reduction achieving the equivalent effect on the Qualified Transfer Path is established by the Receiver and/or the Sender.

ii. Responsible Entities may arrange among themselves to make curtailments called for by this USF Reduction Procedure in a manner other than prescribed provided that the arrangements are as effective as the identified schedule curtailment in reducing USF across the Qualified Transfer Path. Responsible Entities may make bilateral arrangements, which will enable a Responsible Entity with schedules on the affected Qualified Transfer Path to make the required curtailments in lieu of making larger curtailments in schedules over other parallel paths. Where alternative schedule adjustments are utilized, it is the Receiver's responsibility to cause schedule adjustments to be effected which provide the same reduction in flow across the Qualified Transfer Path as would have been achieved by the prescribed reduction in the Contributing Schedule.

iii. The total amount of requested schedule reduction may be apportioned to the applicable schedules at the discretion of the Receiver subject to item iv below.

iv. Irrespective of the schedules altered or the manner in which they are altered, each Responsible Entity's overall net reduction in Actual Flow across the constrained Qualified Transfer Path must be equivalent to or greater than the reduction which would have been achieved had the identified schedule reduction occurred as requested.

v. System dispatchers or real-time schedulers should identify in advance those schedules that qualify for curtailment requests for all Qualified Transfer Paths. This will expedite implementation of this USF Reduction Procedure when requested.

vi. While this USF Reduction Procedure does not expect receivers to curtail schedules which would result in loss of firm load, nothing in this USF Reduction Procedure shall relieve the receiver of the obligation to achieve the required reduction in USF across the constrained Qualified Transfer Path.”

Contributing Schedule curtailments apply to schedules in place before initiation of the USF Procedure at Step 4 (First level Contributing Schedule Curtailment) or higher step. At the time a Step 4 Level 1 USF Action or higher step is initiated, Schedules are established by the existence of an “Implemented” NERC Transaction Tag.

Restricted Transactions

After the USF Event is declared, a transaction with greater than a 5% Transfer Distribution Factor (TDF) on the Qualified Path in the qualified direction will be considered a “Restricted Transaction.” Changes to Restricted Transactions, other than
the specific curtailments used to comply with relief obligations, cannot be made unless some alternative action is taken to compensate for the full impact on the Qualified Path. This applies to: New transaction, and Extensions or Adjustments to existing transaction.”

If two or more Qualified Paths become simultaneously constrained to the point where the curtailment of contributing schedules is necessary, schedule curtailments which relieve USF on one path but increase USF on any other curtailed path shall not be made, unless specific procedures or methods are provided to address this condition. The entity shall be compliant with this standard although the required curtailments were not made.

C. Measures

M1.

Responsible Entities shall take actions as requested by Qualified Transfer Path Operators that result in the specified amount of Unscheduled Flow Relief for the applicable Qualified Transfer Path. These actions include, but are not limited to, one or a combination of schedule curtailments, schedule increases, and operation of non-Qualified Controllable Devices.

It is the responsibility of each Responsible Entity to have in place procedures for receipt of notification of a Qualified Transfer Path Operators request. Failure to provide the required USF relief or to increase USF shall not be excused due to failure to receive notification.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Western Electricity Coordinating Council (WECC)

1.2 Compliance Monitoring Period

The actions taken by Responsible Entities in response to requests by the Qualified Transfer Path Operators shall be documented and supplied to WECC Staff in accordance with the Plan Section 9. The WECC Staff will make specific requests for data submittal, including the specification of dates, hours, and required submittal dates.

Responsible Entities are to report the actions taken in accordance with the Plan for each hour of a curtailment period. Each Responsible Entity shall promptly provide documentation, as requested by UFAS and/or WECC Staff, of all such accommodation, control or curtailment actions taken by its dispatchers, system operators or real-time schedulers. In addition, each Transfer Path Operator shall provide documentation to the WECC staff regarding actions taken or not taken in filling its responsibilities during each curtailment period. Responsible Entities' documentation shall use formats and reporting conventions developed and monitored by the WECC Operating Committee. Responsible Entities may use the reporting applications as adopted by the Unscheduled Flow Administrative Subcommittee (UFAS) to submit curtailment data. On or before the tenth Business Day following the date of a WECC Staff USF letter request for data, each entity shall distribute to the WECC Staff the USF information at the e-mail
addresses specified on the WECC web site. The USF information shall include the identification of Responsible Entities who failed to adjust schedules according to this USF Reduction Procedure.

Each Responsible Entity identified in Section A.4.1 shall submit the completed USF Reduction Procedure Reporting output to the WECC Staff by no later than 5:00 p.m. Mountain Time on the tenth Business Day following the date of the WECC Staff USF letter. UFAS has developed an Administrative Practice 007 “Curtailment Event Selection Evaluation Process” that is utilized to select one event per path per month for Compliance Evaluation. WECC Staff selects one event during the first week following the month to review.

1.3 Data Retention

Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

1.4. Additional Compliance Information

For purposes of applying the sanctions for violations of this criterion, the “Sanction Measure” is the greater of the maximum hourly integrated MWh of “Required Relief” or “USF Increase” (truncated to the nearest MW) during the specified period multiplied by 50, and the “Specified Period” is the most recent calendar month. The sanctions shall be assessed on a monthly basis, but for purposes of determining the applicable column in the table in Sanction Table, all occurrences within the specified period of the most recent calendar month and all immediately preceding consecutive calendar months in which at least one instance of non-compliance occurred shall be considered. For example, if the maximum hourly integrated Required Relief was 25 MW and the maximum hourly integrated USF Increase for the period was 30 MW, the Sanction Measure for the period would be 30 MW times 50 or 1,500. If the maximum hourly integrated Required Relief was 24 MW and the maximum hourly integrated USF Increase was 10 MW, the Sanction Measure for the period would be 24 times 50 or 1,200.

2. Levels of Non-Compliance

Sanction Measure: Normal Path Rating

For each separate USF Schedule Curtailment event (multiple hours), the level of the non-compliance shall be based upon the magnitude of MWh relief required and the ratio of actual MWh relief provided to the required MWh of relief (truncated to the nearest MWh) for every hour that the curtailment requirement was in effect. The non-compliance levels are indicated in the table below:

<table>
<thead>
<tr>
<th>Ratio of actual MWh relieved to the required MWh of relief (%) and magnitude of the required MWh of relief:</th>
<th>Level of Non-Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>100% &gt; percent relief ≥ 90% or required MWh of relief ≤ 5 and was not achieved.</td>
<td>Level 1</td>
</tr>
<tr>
<td>90% &gt; percent relief ≥ 75% and required MWh of relief &gt; 5.</td>
<td>Level 2</td>
</tr>
<tr>
<td>75% &gt; percent relief ≥ 60% and required MWh of relief &gt; 5.</td>
<td>Level 3</td>
</tr>
<tr>
<td>percent relief &lt;60% and required MWh of relief &gt; 5.</td>
<td>Level 4</td>
</tr>
<tr>
<td>Failure to Report</td>
<td>Level 4</td>
</tr>
</tbody>
</table>

If an entity during an USF Schedule Curtailment event initiates a Restricted Transaction that increases USF across the Qualified Path requesting relief, without making an equal compensating change to other transactions, the level of noncompliance shall be determined in accordance with the table below.

<table>
<thead>
<tr>
<th>For each hour the percent of USF increases due to changes to Restricted Transactions</th>
<th>Level of Non-Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 % &lt; USF increase ≤ 1 % of the path rating</td>
<td>Level 1</td>
</tr>
<tr>
<td>1 % &lt; USF increase ≤ 2 % of the path rating</td>
<td>Level 2</td>
</tr>
<tr>
<td>2 % &lt; USF increase ≤ 3 % of the path rating</td>
<td>Level 3</td>
</tr>
<tr>
<td>USF increase &gt; 3 % of the path rating</td>
<td>Level 4</td>
</tr>
</tbody>
</table>

For every hour that the curtailment requirement was in effect, the level of non-compliance assessed to an entity shall be the higher level of non-compliance determined under the percent relief and USF increase tables shown above.
Sanction Table

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
<thead>
<tr>
<th>Level of Non-Compliance</th>
<th>Number of Occurrences at a Given Level within Specified Period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Level 1</td>
<td>Letter (A)</td>
</tr>
<tr>
<td>Level 2</td>
<td>Letter (B)</td>
</tr>
<tr>
<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
</tbody>
</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

3 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.
DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in the Reliability Agreement and as set out below:

**Business Day** means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**Normal Path Rating** is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

**WECC Table 2** means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

EXCUSE OF PERFORMANCE

**A. Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

**B. Specific Excuses**

1. **Governmental Order**

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).
2. **Order of Reliability Coordinator**

The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability
Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Reliability Agreement. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

5. Participation in Field Testing

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-
compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
A. Introduction

1. Title: Available Transmission System Capability
2. Number: MOD-001-1
3. Purpose: To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors
4. Applicability:
   4.1. Transmission Service Provider.
   4.2. Transmission Operator.
5. Proposed Effective Date: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
   - The Area Interchange Methodology, as described in MOD-028
   - The Rated System Path Methodology, as described in MOD-029
   - The Flowgate Methodology, as described in MOD-030

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

   R2.1. Hourly values for at least the next 48 hours.
   R2.2. Daily values for at least the next 31 calendar days.
   R2.3. Monthly values for at least the next 12 months (months 2-13).

R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

   R3.1. Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

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1 All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.
R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:

R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

R3.2.2. A rationale for that accounting specified in R3.2.

R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

R3.4. The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider:
  - Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
  - Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
  - Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

R3.6.3. How outages from other Transmission Service Providers that cannot be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R4.1. Each Planning Coordinator associated with the Transmission Service Provider’s area.

R4.2. Each Reliability Coordinator associated with the Transmission Service Provider’s area.

R4.3. Each Transmission Operator associated with the Transmission Service Provider’s area.
R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider’s area.

R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider’s area.

R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider’s area.

R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

R8.2. Daily values, once per day.

R8.3. Monthly values, once per week.

R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor’s ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are

Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.
committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

- Dispatch Order
- Participation Factors
- Block Dispatch

- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.1.1.** If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available.
R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available.

R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available.

R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

C. Measures

M1. The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator’s operating area. (R1).

M2. The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):
- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

M3. The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

M4. The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

M5. The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

M6. The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning.
When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

M7. The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

M8. The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

M9. The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.

- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.

- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.

- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.

- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.
2. **Violation Severity Levels**

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.</td>
</tr>
<tr>
<td>R2.</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
</tr>
<tr>
<td></td>
<td>- The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.</td>
<td>- The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.</td>
<td>- The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 11 hours.</td>
<td>- The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours.</td>
</tr>
<tr>
<td></td>
<td>- Has calculated daily ATC or AFC values for more than the next 9 months but less than the next 12 months.</td>
<td>- Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.</td>
<td>- Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.</td>
<td>- Has calculated daily ATC or AFC values for less than the next 8 calendar days.</td>
</tr>
<tr>
<td></td>
<td>- Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.</td>
<td>- Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.</td>
<td>- Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.</td>
<td>- Has calculated monthly ATC or AFC values for less than the next 4 months.</td>
</tr>
</tbody>
</table>
|      | Did not use the selected methodology(ies) to calculate ATC. | | | - Did not use the selected methodology(ies) to calculate ATC.
### Standard MOD-001-1 — Available Transmission System Capability

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R3.</td>
<td>• The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.</td>
<td>• The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.</td>
<td>• The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago. OR • The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3.</td>
<td>• The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago. OR • The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3.</td>
</tr>
<tr>
<td>R4.</td>
<td>• The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation.</td>
<td>• The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation.</td>
<td>• The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. OR • The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation.</td>
<td>• The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation. OR • The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation.</td>
</tr>
<tr>
<td>R5.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Service Provider did not make the ATCID available to the parties described in R4.</td>
</tr>
<tr>
<td>R #</td>
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<tr>
<td>R6.</td>
<td>The Transmission Operator determined TTC or TFC using assumptions more</td>
<td>The Transmission Operator determined TTC or TFC using assumptions more</td>
<td>The Transmission Operator determined TTC or TFC using assumptions more</td>
<td>The Transmission Operator determined TTC or TFC using assumptions more</td>
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<td>limiting than those used in planning of operations for the studied time</td>
<td>limiting than those used in planning of operations for the studied time</td>
<td>limiting than those used in planning of operations for the studied time</td>
<td>limiting than those used in planning of operations for the studied time</td>
</tr>
<tr>
<td></td>
<td>period for more than zero ATC Paths or Flowgates, but not more than 5%</td>
<td>period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or</td>
<td>period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more</td>
<td>period for more than 15% of all ATC Paths or Flowgates (whichever is greater).</td>
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<td></td>
<td>of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is</td>
<td>Flowgate (whichever is greater), but not more than 10% of all ATC Paths or</td>
<td>than 15% of all ATC Paths or Flowgates (whichever is greater).</td>
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<td></td>
<td>greater).</td>
<td>Flowgates or 2 ATC Paths or Flowgates (whichever is greater).</td>
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<td></td>
<td>The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of</td>
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<tr>
<td>R7</td>
<td>The Transmission Service Provider determined ATC or AFC using assumptions</td>
<td>The Transmission Service Provider determined ATC or AFC using assumptions</td>
<td>The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of</td>
<td>The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of</td>
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<td>more limiting than those used in planning of operations for the studied</td>
<td>more limiting than those used in planning of operations for the studied</td>
<td>operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or</td>
<td>operations for the studied time period for more than 15% of all ATC Paths or Flowgates (whichever is greater).</td>
</tr>
<tr>
<td></td>
<td>time period for more than 5% of all ATC Paths or Flowgates, but not more</td>
<td>time period for more than 10% of all ATC Paths or Flowgates or 1 ATC Path or</td>
<td>Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates</td>
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<td></td>
<td>than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever</td>
<td>Flowgate (whichever is greater), but not more than 15% of all ATC Paths or</td>
<td>(whichever is greater).</td>
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<td></td>
<td>is greater).</td>
<td>Flowgates or 2 ATC Paths or Flowgates (whichever is greater).</td>
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<td>R8.</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
<td>One or more of the following:</td>
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<td>- For Hourly, the values described in the ATC equation changed and the</td>
<td>- For Hourly, the values described in the ATC equation changed and the</td>
<td>- For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate</td>
<td>- For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate</td>
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<tr>
<td></td>
<td>Transmission Service provider did not calculate for one or more hours but</td>
<td>Transmission Service provider did not calculate for one or more hours but</td>
<td>for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</td>
<td>for more than 25 hours, and was in excess of the 175-hour per year requirement.</td>
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<tr>
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<td>not more than 15 hours, and was in excess of the 175-hour per year</td>
<td>not more than 20 hours, and was in excess of the 175-hour per year requirement.</td>
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<td>requirement.</td>
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<td>One or more of the following:</td>
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<td>- For Daily, the values</td>
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Adopted by NERC Board of Trustees: August 26, 2008
<table>
<thead>
<tr>
<th>R #</th>
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<th>Severe VSL</th>
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<tr>
<td></td>
<td>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</td>
<td>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</td>
<td>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</td>
<td>described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</td>
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<tr>
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<td>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</td>
<td>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</td>
<td>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</td>
<td>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</td>
</tr>
<tr>
<td>R9</td>
<td>N/A</td>
<td>The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request.</td>
<td>The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request.</td>
<td>The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request.</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Capacity Benefit Margin
2. Number: MOD-004-1
3. Purpose: To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.
4. Applicability:
   4.1. Load-Serving Entities.
   4.2. Resource Planners.
   4.3. Transmission Service Providers.
   4.4. Balancing Authorities.
   4.5. Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.
5. Effective Date: First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Transmission Service Provider that maintains CBM shall prepare and keep current a “Capacity Benefit Margin Implementation Document” (CBMID) that includes, at a minimum, the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]

R1.1. The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.

R1.2. The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.

R1.3. The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.

R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider’s area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider’s...
area, and notify those entities of any changes to the CBMID prior to the effective date of the change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.1.** Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R3.2.** Identifying expected import path(s) or source region(s).

**R4.** Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R4.2.** Identifying expected import path(s) or source region(s).

**R5.** At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider’s area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider’s area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider’s area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R5.2.** Be allocated as follows:
- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

**R6.** At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: *Violation Risk Factor: Lower* [*Time Horizon: Long-term Planning*]

**R6.1.** Reflect consideration of each of the following if available:
- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner’s area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner’s area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner’s area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R6.2.** Be allocated as follows:
- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

**R7.** Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider’s system of the amount of CBM set aside. *Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

**R8.** Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they
had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]

R9.1. Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.

R9.2. To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.

R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]

R11. When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]

R12. The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an “energy deficient entity” under an EEA 2 if: [Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]

R12.1. The CBM is available

R12.2. The EEA 2 is declared within the Balancing Authority Area of the “energy deficient entity,” and

R12.3. The Load of the “energy deficient entity” is located within the Transmission Service Provider’s area.

C. Measures

M1. Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

M2. Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

1 See Attachment 1-EOP-002-0 for explanation.
M3. Each Load-Serving Entity that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

M4. Each Resource Planner that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

M5. Each Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (R5)

M6. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years two through ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement. (Note that CBM values may legitimately be zero.) (R6)

M7. Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside. (R7)

M8. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside. (R8)

M9. Each Transmission Service Provider that maintains CBM and each Transmission Planner shall provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R9. (R9)

M10. Each Load-Serving Entity and Balancing Authority shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time it requested to import energy using firm Transfer Capability set aside as CBM, it was in an EEA 2 or higher. (R10)

M11. Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived Real-time timing and ramping requirements when approving an Arranged Interchange using CBM. (R11)

M12. Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange meeting the criteria in R12. (R12)

D. Compliance
1. **Compliance Monitoring Process**

1.1. **Compliance Enforcement Authority (CEA)**
   Regional Entity.

1.2. **Compliance Monitoring Period and Reset Time Frame**
   Not applicable.

1.3. **Data Retention**
   - The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force during the past three calendar years plus the current year to show compliance with R1.
   - The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, R5, R7, R9, and R12 for the most recent three calendar years plus the current year.
   - The Load-Serving Entity shall each maintain evidence to show compliance with R3 and R10 for the most recent three calendar years plus the current year.
   - The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
   - The Transmission Planner shall maintain evidence to show compliance with R6, R8, and R9 for the most recent three calendar years plus the current year.
   - The Balancing Authority shall maintain evidence to show compliance with R10 and R11 for the most recent three calendar years plus the current year.
   - The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
   - If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
   - The Compliance Enforcement Authority shall keep the last audit records and all requested and subsequently submitted audit records.

1.4. **Compliance Monitoring and Enforcement Processes:**
   The following processes may be used:
   - Compliance Audits
   - Self-Certifications
   - Spot Checking
   - Compliance Violation Investigations
   - Self-Reporting
- Complaints

1.5. **Additional Compliance Information**

None.
## Violation Severity Levels

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<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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</table>
| R1. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.  
**OR**  
The CBM maintaining Transmission Service Provider’s CBMID does not address one of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.  
**OR**  
The CBM maintaining Transmission Service Provider’s CBMID does not address two of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago.  
**OR**  
The Transmission Service Provider that maintains CBM does not have a CBMID;  
**OR**  
The CBM maintaining Transmission Service Provider’s CBMID does not address three of the sub requirements. |
| R2. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID after the effective date of the change, but not more than 30 calendar days after the effective date of the change. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 30 or more calendar days but not more than 60 calendar days after the effective date of the change. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 60 or more calendar days but not more than 90 calendar days after the effective date of the change.  
**OR**  
The CBM maintaining Transmission Service Provider’s CBMID made available the CBMID to at least one, but not all, of the entities specified in R2. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID more than 90 calendar days after the effective date of the change.  
**OR**  
The CBM maintaining Transmission Service Provider’s CBMID made available the CBMID to none of the entities specified in R2. |
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</table>
| R3. | The Load-Serving Entity did not use one of the methods described in R3.1  
OR  
The Load-Serving Entity did not identify paths or regions as described in R3.2 | The Load-Serving Entity did not use one of the methods described in R3.1  
AND  
The Load-Serving Entity did not identify paths or regions as described in R3.2 | |
| R4  | The Resource Planner did not use one of the methods described in R4.1  
OR  
The Resource Planner did not identify paths or regions as described in R4.2 | The Resource Planner did not use one of the methods described in R4.1  
AND  
The Resource Planner did not identify paths or regions as described in R4.2 | |
| R5. | The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established.  
OR  
The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available.  
OR  
The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as described in R5.1 | The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.  
OR  
The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more paths or regions as described in R5.1 | The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established.  
OR  
The Transmission Service Provider that maintains CBM failed to establish an initial value for CBM.  
OR  
The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more paths or regions as described in R5.1 |
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<td>described in R5.2.</td>
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<td>paths or regions as described in R5.2</td>
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<td>R6.</td>
<td></td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 16 months, but not more than 19 months, after the last time the values were established.</td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 19 months, but not more than 22 months, after the last time the values were established.</td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 22 months after the last time the values were established.</td>
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<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available.</td>
<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available.</td>
<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available.</td>
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<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation</td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available.</td>
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Adopted by NERC Board of Trustees: November 13, 2008
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<tr>
<td>R7</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.</td>
<td>OR The Transmission Service Provider that maintains CBM notified none of the entities as required.</td>
</tr>
<tr>
<td></td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.</td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.</td>
<td>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.</td>
<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified none of the entities as required.</td>
</tr>
<tr>
<td>R8</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.</td>
<td>The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.</td>
<td>OR The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified none of the entities as required.</td>
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<td>R #</td>
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<td>Moderate VSL</td>
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<tr>
<td>R9.</td>
<td>The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 30, but not more than 45, days after the submission of the request.</td>
<td>The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 45, but not more than 60, days after the submission of the request.</td>
<td>The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 60, but not more than 75, days after the submission of the request.</td>
<td>The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 75 days after the submission of the request. OR The Transmission Service Provider or Transmission Planner provided at least one, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.</td>
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<tr>
<td>R10.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>A Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher.</td>
</tr>
<tr>
<td>R11.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so.</td>
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<tr>
<td>R #</td>
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<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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<tr>
<td>R12.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Service Provider failed to approve an Arranged Interchange for CBM that met the criteria described in R12 without a reliability reason to do so.</td>
</tr>
</tbody>
</table>
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: May 13, 2009

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
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

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<td>0</td>
<td>September 17, 2007</td>
<td>Corrected R1. — changed “preservation” to “reservation.”</td>
<td>Errata</td>
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<tr>
<td>0.1</td>
<td>October 29, 2008</td>
<td>– Corrected Measure M1. — changed “preservation” to “reservation.”</td>
<td>Errata</td>
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<td>– BOT adopted errata changes; changed version number to “0.1”</td>
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<td>May 13, 2009</td>
<td>FERC Approved — Updated Effective date and footer</td>
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A. Introduction

1. Title: Documentation of the Use of Capacity Benefit Margin
2. Number: MOD-007-0
3. Purpose: To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria.
4. Applicability:
   4.1. Transmission Service Provider
5. Effective Date: April 1, 2005

B. Requirements

   R1. Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities’ Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider’s procedure for use of CBM.)

   R2. The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a website accessible by the Regional Reliability Organizations, NERC, and transmission users.
      R2.1. Circumstances.
      R2.2. Duration.
      R2.3. Amount of CBM used.

C. Measures

   M1. The Transmission Service Provider shall have evidence that it posted an after-the-fact disclosure that energy was scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) on a website accessible by the Regional Reliability Organizations, NERC, and transmission users.

   M2. If the Transmission Service Provider had energy scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) the Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that includes the elements required by Reliability Standard MOD-007_R2.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Compliance Monitor: Regional Reliability Organizations.
   1.2. Compliance Monitoring Period and Reset Timeframe
       Within 15 calendar days of the use of CBM (excluding Non-Firm Transmission Sales)
   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: Information pertaining to the use of CBM during an Energy Emergency was provided, but was not made available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users, or meets only two of the three requirements as listed in Reliability Standard MOD-007-0_R2.

2.3. Level 3: Not applicable.

2.4. Level 4: After the use of CBM (excluding Non-Firm Transmission Sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Reliability Standard MOD-007-0_R2, or no information was provided.

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. **Title:** Transmission Reliability Margin Calculation Methodology
2. **Number:** MOD-008-1
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   4.1. Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information:

[R1.1. Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:
- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions).
- Reserve sharing requirements.
- Inertial response and frequency bias.

R1.2. The description of the method used to allocate TRM across ATC Paths or Flowgates.

R1.3. The identification of the TRM calculation used for the following time periods:
   - **R1.3.1.** Same day and real-time.
   - **R1.3.2.** Day-ahead and pre-schedule.
   - **R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.
R2. Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R3. Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

R4. Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R5. The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

M1. Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

M2. Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

M3. Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

M4. Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

M5. Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority
Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame
Not applicable.

1.3. Data Retention
The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes
Any of the following may be used:
- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information
None.
### 2. Violation Severity Levels

<table>
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<tr>
<th>R #</th>
<th>Lower VSL</th>
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<th>High VSL</th>
<th>Severe VSL</th>
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<tbody>
<tr>
<td>R1.</td>
<td>The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.</td>
<td>The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago. <strong>OR</strong> The Transmission Operator’s TRMID does not address one of the following:</td>
<td>The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago. <strong>OR</strong> The Transmission Operator’s TRMID does not address two of the following:</td>
<td>The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more. <strong>OR</strong> The Transmission Operator does not have a TRMID. <strong>OR</strong> The Transmission Operator’s TRMID does not address three of the following:</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>One or both of the following:</td>
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<tr>
<td>R2.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. <strong>OR</strong> The Transmission Operator included components of CBM in TRM.</td>
</tr>
<tr>
<td>R3.</td>
<td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days.</td>
<td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.</td>
<td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.</td>
<td>The Transmission Operator did not make the TRMID available for 90 days or more.</td>
</tr>
<tr>
<td>R4</td>
<td>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing.</td>
<td>The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).</td>
<td>The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.</td>
<td>The Transmission Operator did not establish TRM OR The last determination of TRM was more than 18 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.</td>
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<tr>
<td>R5</td>
<td>The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.</td>
<td>The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).</td>
<td>The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.</td>
<td>The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing.</td>
</tr>
</tbody>
</table>
Standard MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation

A. Introduction

1. Title: Steady-State Data for Modeling and Simulation of the Interconnected Transmission System

2. Number: MOD-010-0

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. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1
   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

       Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe
As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention
None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. Title: Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures.
2. Number: MOD-011-0
3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:

R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.

R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.

R1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-008-1 and FAC-009-1) equipment status, and metering locations.

R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-008-1 and FAC-009-1), and equipment status.

R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.

R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.

R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection’s steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to
Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.

C. Measures

M1. The Regional Reliability Organization shall have documentation of its Interconnection’s steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0 R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard MOD-011-0 R1.

2.2. Level 2: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard MOD-011-0 R1.

2.3. Level 3: Not applicable.

2.4. Level 4: Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in Reliability Standard MOD-011-0 R1.

E. Regional Differences

1. None identified.

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<td>March 18, 2008</td>
<td>Corrected references to FAC-004-0 and FAC-005-0 since these standards were retired and replaced with FAC-008-1 and FAC-009-1.</td>
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A. Introduction

1. **Title:** Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.
2. **Number:** MOD-012-0
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. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - 4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - 4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - 4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. **Compliance Monitoring Process**
   1.1. **Compliance Monitoring Responsibility**
       
       Compliance Monitor: Regional Reliability Organizations.
1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0 R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0 R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

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<td>September 16, 2005</td>
<td>Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).</td>
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A. Introduction
1. Title: Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures
2. Number: MOD-013-1
3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. Applicability:
   4.1. Regional Reliability Organization.
5. Effective Date: Six months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:

R1.1. Design data shall be provided for new or refurbished excitation systems (for synchronous generators and synchronous condensers) at least three months prior to the installation date.
   R1.1.1. If design data is unavailable from the manufacturer 3 months prior to the installation date, estimated or typical manufacturer’s data, based on excitation systems of similar design and characteristics, shall be provided.

R1.2. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.
   R1.2.1. Estimated or typical manufacturer’s dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.2.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:
   − The use of non-detailed vs. detailed models,
   − The netting of small generating units with bus load, and
   − The combining of multiple generating units at one plant.

R1.3. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.
R1.4. Dynamics data representing electrical Demand characteristics as a function of frequency and voltage.

R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010 Requirement 1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection’s data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection’s dynamics data requirements and reporting procedures and shall provide the documentation as specified in Requirement 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Data requirements and reporting procedures: on request (five business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the five areas defined in R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Data requirements and reporting procedures provided were incomplete in two or more of the five areas defined in R1.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the five areas defined in R1.

E. Regional Differences

None identified.
### Version History

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A. Introduction

1. Title: Development of Steady-State System Models
2. Number: MOD-014-0
3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steady-state system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels.

R2. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steady-state models to NERC in accordance with each Interconnection’s schedule for submission.

C. Measures

M1. Each Regional Reliability Organization shall have Interconnection-specific steady-state system models as specified in MOD-014-0_R1 and MOD-014-0_R2.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Compliance Monitor: NERC.
   1.2. Compliance Monitoring Period and Reset Timeframe
       Development of steady-state system models: annually, as determined by each Interconnection’s schedule.
       Most recent steady-state 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 either was 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 identified.

**Version History**

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A. Introduction

1. Title: Development of Dynamics System Models
2. Number: MOD-015-0
3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

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 steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R1.

   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 Timeframe
       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**

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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**

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<td>0.1</td>
<td>October 29, 2008</td>
<td>BOT adopted errata changes; changed version number to “0.1”</td>
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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: May 13, 2009

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

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<td>May 13, 2009</td>
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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: May 13, 2009

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
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.

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<td>April 18, 2008</td>
<td>Revised R1. And D1.2. to reflect update in version from “MOD-016-0_R1” to MOD-016-1_R1.”</td>
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<td>May 13, 2009</td>
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A. Introduction

1. Title: Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load

2. Number: MOD-018-0

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: April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner’s report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:

   R1.1. Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and

   R1.2. Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.

   R1.3. Items (MOD-018-0_R1.1) and (MOD-018-0_R1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R1.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that its actual and forecast demand data were addressed as described in the reporting procedures developed for Reliability Standard MOD-018-0_R1.

M2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report current information for Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

On Request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Information for Reliability Standard MOD-018-0 item R1.1 or R1.2 was not provided.

2.2. Level 2: Information for Reliability Standards MOD-018-0 items R1.1 and R1.2 was not provided.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

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<td>April 1, 2005</td>
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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: May 13, 2009

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.

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<td>February 8, 2005</td>
<td>Approved by BOT</td>
<td>Revised</td>
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<td>0</td>
<td>July 24, 2007</td>
<td>Changed reference R1. and Dl.1.2. to “MOD-016-0_R1” to MOD-016-1_R1.” (New version number.)</td>
<td>Errata</td>
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<td>0.1</td>
<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to “0.1”.</td>
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<tr>
<td>0.1</td>
<td>May 13, 2009</td>
<td>FERC Approved — Updated Effective Date and Footer</td>
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A. Introduction

1. Title: Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
2. Number: MOD-020-0
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. Transmission Planner
   4.3. Resource Planner

5. Effective Date: April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Regional Reliability Organization.
   1.2. Compliance Monitoring Period and Reset Timeframe
       On request (within 30 calendar days).
   1.3. Data Retention
       None specified.
   1.4. Additional Compliance Information
       None.

2. Levels of Non-Compliance
   2.1. Level 1: Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.
   2.2. Level 2: Not applicable.
2.3.  Level 3: Not applicable.

2.4.  Level 4: Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.

E. Regional Differences

1. None identified.

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A. Introduction

1. Title: Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts.

2. Number: MOD-021-0.1

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 (DSM) programs is needed.

4. Applicability:
   4.1. Load-Serving Entity
   4.2. Transmission Planner
   4.3. Resource Planner

5. Effective Date: April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner’s forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 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 Timeframe
On request (within 30 calendar days).

1.3. **Data Retention**
None specified.

1.4. **Additional Compliance Information**
None.

2. **Levels of Non-Compliance**

2.1. **Level 1:** Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.

2.2. **Level 2:** Not applicable.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.

**E. Regional Differences**

1. None identified.

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<td>April 15, 2009</td>
<td>R1. – comma inserted after Load-Serving Entity</td>
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A. Introduction
1. Title: Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts.
2. Number: MOD-021-0
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 (DSM) programs is needed.
4. Applicability:
   4.1. Load-Serving Entity
   4.2. Transmission Planner
   4.3. Resource Planner
5. Effective Date: April 1, 2005

B. Requirements
R1. The Load-Serving Entity Transmission Planner and Resource Planner’s forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.
R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.
R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures
M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.
M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.
M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 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 Timeframe
   On request (within 30 calendar days).

1.3. Data Retention
   None specified.

1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance
   2.1. Level 1: Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.
   2.2. Level 2: Not applicable.
   2.3. Level 3: Not applicable.
   2.4. Level 4: Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.

E. Regional Differences
   1. None identified.

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A. Introduction
1. **Title:** Verification of Generator Gross and Net Real Power Capability
2. **Number:** MOD-024-1
3. **Purpose:** To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.
4. **Applicability**
   4.1. Regional Reliability Organization.
   4.2. Generator Owner.
5. **Effective Dates:**
   - Requirement 1 and Requirement 2 — April 1, 2006.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:
   R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
   R1.2. Criteria for reporting generating unit auxiliary loads.
   R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.
   R1.4. Periodicity and schedule of model and data verification and reporting.
   R1.5. Information to be verified and reported:
      R1.5.1. Seasonal gross and net Real Power generating capabilities.
      R1.5.2. Real power requirements of auxiliary loads.
      R1.5.3. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators,
Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization’s procedures.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

       For Regional Reliability Organization: NERC

       For Generator Owner: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

       One calendar year.

   1.3. Data Retention

       The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

       The Generator Owner shall retain information from the most current and prior verification.

       The Compliance Monitor shall retain any audit data for three years.

   1.4. Additional Compliance Information

       The Regional Reliability Organization and Generator Owner 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 Regional Reliability Organization:

   2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

       2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

       2.1.2 No evidence that procedures were distributed as required in R2.

   2.2. Level 2: There shall be a level two non-compliance if both of the following conditions are present:

       2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

       2.2.2 No evidence that procedures were distributed as required in R2.

   2.3. Level 3: Procedures did not meet R1.3.

   2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3
3. Levels of Non-Compliance for Generator Owner:

3.1. **Level 1:** Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner’s units as required by the regional procedures.

3.2. **Level 2:** Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner’s units as required by the regional procedures.

3.3. **Level 3:** Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner’s units as required by the regional procedures.

3.4. **Level 4:** Complete, verified generator data were provided for less than 94% of a generator owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

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| Version 1 | 12/01/05 | 1. Changed tabs in footer.  
3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”  
4. Added “periods” to items where appropriate.  
5. Changed apostrophes to “smart” symbols.  
6. Changed “Timeframe” to “Time Frame” in item D, 1.2.  
7. Lower cased all instances of “regional” in section D.3.  
8. Removed the word “less” after 94% in section 3.4. Level 4. | 01/20/06 |
A. Introduction

1. Title: Verification of Generator Gross and Net Reactive Power Capability

2. Number: MOD-025-1

3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. Applicability

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. Effective Dates:

   Requirement 1 and Requirement 2 — January 1, 2007

   Requirement 3:

   January 1, 2008 — 1st 20% compliant

   January 1, 2009 — 2nd 20% compliant

   January 1, 2010 — 3rd 20% compliant

   January 1, 2011 — 4th 20% compliant

   January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

   R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

   R1.2. Criteria for reporting generating unit auxiliary loads.

   R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

   R1.4. Periodicity and schedule of model and data verification and reporting.

   R1.5. Information to be reported:

       R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

       R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

       R1.5.3. Verified Reactive Power of auxiliary loads.

       R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the
Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization’s procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner 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 Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.
2.3. Level 3: Procedures did not meet R1.3.
2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner’s units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner’s units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner’s units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

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5. Changed apostrophes to “smart” symbols.  
6. Changed “Timeframe” to “Time Frame” in item D, 1.2.  
7. Lower cased all instances of “regional” in section D.3. |

Change Tracking: 01/20/06
A. Introduction

1. **Title:** Area Interchange Methodology
2. **Number:** MOD-028-1
3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.
4. **Applicability:**
   4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

   R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

   R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

   R1.3. Any contractual obligations for allocation of TTC.

   R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.

   R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:

      R1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

      R1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

      R1.5.3. The source/sink or POR/POD identification and mapping to the model.
R1.5.4. If the Transmission Service Provider’s ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R2.1. Modeling data and topology of its Reliability Coordinator’s area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

R2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider’s area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. Load forecast for the applicable period being calculated.

R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.
R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R4.1. Use all Contingencies meeting the criteria described in the ATCID.

R4.2. Respect any contractual allocations of TTC.

R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink.

- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.

- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the sink.
Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below:  
*Violation Risk Factor: Lower* [Time Horizon: Operations Planning]

**R5.1.** At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *Violation Risk Factor: Lower* [Time Horizon: Operations Planning]

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider’s system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater.¹

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider’s ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider’s contractual rights.

¹ The Transmission operator may honor distribution factors less than 5% if desired.
**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: 

*Violation Risk Factor: Lower*  
*Time Horizon: Operations Planning*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: 

*Violation Risk Factor: Lower*  
*Time Horizon: Operations Planning*

\[
ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F
\]

Where:

- **NITS_F** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider’s area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

- **GF_F** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

- **PTP_F** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

- **ROR_F** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

- **OS_F** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments (ETC_NF) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: 

*Violation Risk Factor: Lower*  
*Time Horizon: Operations Planning*

\[
ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}
\]

Where:

- **NITS_{NF}** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service, including the capacity used to serve bundled load within the Transmission Service Provider’s area with external sources)
reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF\textsubscript{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP\textsubscript{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS\textsubscript{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: \textit{[Violation Risk Factor: Lower]} \textit{[Time Horizon: Operations Planning]}

\[ \text{ATC}_F = \text{TTC} - \text{ETC}_F - \text{CBM} - \text{TRM} + \text{Postbacks}_F + \text{counterflows}_F \]

Where:

\text{ATC}_F is the firm Available Transfer Capability for the ATC Path for that period.

\text{TTC} is the Total Transfer Capability of the ATC Path for that period.

\text{ETC}_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

\text{CBM} is the Capacity Benefit Margin for the ATC Path during that period.

\text{TRM} is the Transmission Reliability Margin for the ATC Path during that period.

\text{Postbacks}_F are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

\text{counterflows}_F are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: \textit{[Violation Risk Factor: Lower]} \textit{[Time Horizon: Operations Planning]}

\[ \text{ATC}_{NF} = \text{TTC} - \text{ETC}_F - \text{ETC}_{NF} - \text{CBM}_S - \text{TRM}_U + \text{Postbacks}_{NF} + \text{counterflows}_{NF} \]

Where:

\text{ATC}_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

\text{TTC} is the Total Transfer Capability of the ATC Path for that period.

\text{ETC}_F is the sum of existing firm Transmission commitments for the ATC Path during that period.
ETC\textsubscript{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM\textsubscript{S} is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM\textsubscript{U} is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

Postbacks\textsubscript{NF} are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows\textsubscript{NF} are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated
duration of the outage; provided such outage is expected to last 24 hours or longer in
duration per the specifications in R5. (R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation)
that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest
calculated TTC values along with a dated copy of email notices or other equivalent
evidence to show that it provided its Transmission Service Provider with the most
current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by
recalculating firm ETC for any specific time period as described in (MOD-001 R2),
using the algorithm defined in R8 and with data used to calculate the specified value for
the designated time period. The data used must meet the requirements specified in
MOD-028-1 and the ATCID. To account for differences that may occur when
recalculating the value (due to mixing automated and manual processes), any
recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the
originally calculated value, is evidence that the Transmission Service Provider used the
algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by
recalculating non-firm ETC for any specific time period as described in (MOD-001
R2), using the algorithm defined in R9 and with data used to calculate the specified
value for the designated time period. The data used must meet the requirements
specified in MOD-028-1 and the ATCID. To account for differences that may occur when
recalculating the value (due to mixing automated and manual processes), any
recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the
originally calculated value, is evidence that the Transmission Service Provider used the
algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for
the processes used to implement the algorithm that calculates firm ATCs, as required in
R10. Such documentation must show that only the variables allowed in R10 were used
to calculate firm ATCs, and that the processes use the current values for the variables as
determined in the requirements or definitions. Note that any variable may legitimately
be zero if the value is not applicable or calculated to be zero (such as counterflows,
TRM, CBM, etc…). The supporting documentation may be provided in the same form
and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for
the processes used to implement the algorithm that calculates non-firm ATCs, as
required in R11. Such documentation must show that only the variables allowed in R11
were used to calculate non-firm ATCs, and that the processes use the current values for
the variables as determined in the requirements or definitions. Note that any variable
may legitimately be zero if the value is not applicable or calculated to be zero (such as
counterflows, TRM, CBM, etc…). The supporting documentation may be provided in
the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance
1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
1.5. Additional Compliance Information

None.
2. Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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<tbody>
<tr>
<td>R1.</td>
<td>The Transmission Service Provider has an ATCID but it is missing one of the following:</td>
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<td>• R1.1</td>
<td>The Transmission Service Provider has an ATCID but it is missing two of the following:</td>
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<td></td>
<td>• R1.2</td>
<td>• R1.1</td>
<td>• R1.1</td>
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<td>• R1.3</td>
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<td>• R1.4</td>
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<td>• R1.5 (any one or more of its sub-subrequirements)</td>
<td>• R1.4</td>
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<td>• R1.5 (any one or more of its sub-subrequirements)</td>
<td>• R1.5 (any one or more of its sub-subrequirements)</td>
<td>• R1.5 (any one or more of its sub-subrequirements)</td>
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<tr>
<th>R2.</th>
<th>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</th>
<th>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</th>
<th>One or both of the following:</th>
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<td>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</td>
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<td>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.</td>
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<td>• The Transmission Operator’s model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area.</td>
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<td>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator Areas.</td>
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| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | One or more of the following:  
• The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.  
• The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |

| R4. | The Transmission Operator did not model reservations’ sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater. | The Transmission Operator did not model reservations’ sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater. | The Transmission Operator did not model reservations’ sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater. | One or more of the following:  
• The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.  
• The Transmission Operator did not respect contractual allocations of TTC.  
• The Transmission Operator did not model reservations’ sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.  
• The Transmission Operator did not use firm reservations to estimate interchange or did not  

Adopted by NERC Board of Trustees: August 26, 2008
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| R5. | One or more of the following:  
- The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days  
- The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month | One or more of the following:  
- The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days  
- The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month | One or more of the following:  
- The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days  
- The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month | One or more of the following:  
- The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 16 calendar days  
- The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period  
- The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3 |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | One or more of the following:  
- The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not more than two calendar days after their determination.  
- The Transmission Operator | One or more of the following:  
- The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not more than three calendar days after their determination.  
- The Transmission Operator | One or more of the following:  
- The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not more than four calendar days after their determination.  
- The Transmission Operator | One or more of the following:  
- The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.  
- The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations within 24 hrs of the triggers defined in R5.3 |
### R # Lower VSL

- has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.

### R8. For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.

### R9. For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.
### R10.

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<td>more than 25% of the value calculated in the measure or 25MW, whichever is greater.</td>
<td>more than 35% of the value calculated in the measure or 35MW, whichever is greater...</td>
<td>more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
</tr>
<tr>
<td>R11.</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths, but not more than 10% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
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<td>more than 35% of the value calculated in the measure or 35MW, whichever is greater...</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
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### R11.

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<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
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<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Rated System Path Methodology
2. Number: MOD-029-1
3. Purpose: To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. Applicability:
   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. Proposed Effective Date: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

   R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

   R1.1.1. Includes at least:

   R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

   R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

   R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator’s area by joint operating agreement. (Equivalent representation is allowed.)

   R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

   R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

   R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).
R1.1.5. Uses Load forecast by Balancing Authority.
R1.1.6. Uses Transmission Facility additions and retirements.
R1.1.7. Uses Generation Facility additions and retirements.
R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.
R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner.

R2. The Transmission Operator shall use the following process to determine TTC:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new
TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.  
*Violation Risk Factor: Lower* [Time Horizon: Operations Planning]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.  
*Violation Risk Factor: Lower* [Time Horizon: Operations Planning]

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:  
*Violation Risk Factor: Lower* [Time Horizon: Operations Planning]

\[
ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F
\]

Where:

- **NL** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- **NITS** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- **GF** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”
PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

\[
ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}
\]

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>NF</sub> is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>NF</sub> is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS<sub>NF</sub> is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

\[
ATC_{F} = TTC - ETC_{F} - CBM - TRM + Postbacks_{F} + counterflows_{F}
\]

Where

ATC<sub>F</sub> is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC<sub>F</sub> is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

Postbacks<sub>F</sub> are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.
counterflows\textsubscript{F} are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: \[Violation Risk Factor: \text{Lower}\] \[Time Horizon: \text{Operations Planning}\]

\[
\text{ATC}_{\text{NF}} = \text{TTC} - \text{ETC}_{\text{F}} - \text{ETC}_{\text{NF}} - \text{CBM}_S - \text{TRM}_U + \text{Postbacks}_{\text{NF}} + \text{counterflows}_{\text{NF}}
\]

Where:

\(\text{ATC}_{\text{NF}}\) is the non-firm Available Transfer Capability for the ATC Path for that period.

\(\text{TTC}\) is the Total Transfer Capability of the ATC Path for that period.

\(\text{ETC}_{\text{F}}\) is the sum of existing firm commitments for the ATC Path during that period.

\(\text{ETC}_{\text{NF}}\) is the sum of existing non-firm commitments for the ATC Path during that period.

\(\text{CBM}_S\) is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

\(\text{TRM}_U\) is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

\(\text{Postbacks}_{\text{NF}}\) are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

\(\text{counterflows}_{\text{NF}}\) are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.
C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the
originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

**M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**D. Compliance**

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority**

   Regional Entity.

   1.2. **Compliance Monitoring Period and Reset Time Frame**

   Not applicable.

   1.3. **Data Retention**

   - The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

   - The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)

- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)

- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)

- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)

- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)

- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)

- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.
## 2. Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1.</strong></td>
<td>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. OR The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</td>
<td>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. OR The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</td>
<td>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. OR The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</td>
<td>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. OR The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</td>
</tr>
<tr>
<td><strong>R2</strong></td>
<td>One or both of the following: - The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. - The Transmission Operator does not include one required item in the study report required in R2.8.</td>
<td>One or both of the following: - The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. - The Transmission Operator does not include two required items in the study report required in R2.8.</td>
<td>One or both of the following: - The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. - The Transmission Operator does not include three required items in the study report required in R2.8.</td>
<td>One or more of the following: - The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. - The Transmission Operator did not apply R2.7. - The Transmission Operator does not include four or more required items in the study report required in R2.8.</td>
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<td>R3.</td>
<td>The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
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<tr>
<td>R4.</td>
<td>The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.</td>
<td>The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.</td>
<td>The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.</td>
<td>The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.</td>
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<tr>
<td>R5.</td>
<td>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
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<tr>
<td>R6.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
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<td>absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
</tr>
<tr>
<td>R7.</td>
<td>The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 3 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
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<tr>
<td>R8.</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).</td>
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</tbody>
</table>
A. Introduction

1. Title: Flowgate Methodology
2. Number: MOD-030-02
3. Purpose: To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. Applicability:
   4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
   4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. Proposed Effective Date: The date upon which MOD-030-01 is currently scheduled to become effective.

B. Requirements

R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

   R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

   R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
      R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
      R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
      R1.2.3. The source/sink or POR/POD identification and mapping to the model.
      R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

R2. The Transmission Operator shall perform the following: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

   R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
      R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the
applicable time periods, including use of Special Protection Systems.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.2. Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator’s system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.3. Any limiting Element/Contingency combination at least within its Reliability Coordinator’s Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider’s area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider’s area to a Balancing Area
adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider’s methodology.

**R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

**R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator’s Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the
Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.

- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.

- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall:  

\[ \text{Violation Risk Factor: To Be Determined} \] \[ \text{Time Horizon: Operations Planning} \]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_Fi) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following:  

\[ \text{Violation Risk Factor: To Be Determined} \] \[ \text{Time Horizon: Operations Planning} \]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider’s area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load.
R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider’s ATCID.

R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage\(^1\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:

R6.2.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider’s ATCID.

R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area.

R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage\(^2\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.

R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage\(^3\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.7. The impact of other firm services determined by the Transmission Service Provider.

R7. When calculating the impact of ETC for non-firm commitments (ETC\(_{NFi}\)) for all time periods for a Flowgate the Transmission Service Provider shall sum: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

---

\(^1\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

\(^2\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

\(^3\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.
R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.

R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage\(^4\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.

R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage\(^5\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage\(^6\) used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.7. The impact of other non-firm services determined by the Transmission Service Provider.

R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): \[ \text{Violation Risk Factor: To Be Determined} \]

\[ \text{Time Horizon: Operations Planning} \]

\[ \text{AFC}_F = \text{TFC} - \text{ETC}_F - \text{CBM}_i - \text{TRM}_i + \text{Postbacks}_{Fi} + \text{counterflows}_{Fi} \]

Where:

\[ \text{AFC}_F \] is the firm Available Flowgate Capability for the Flowgate for that period.

\(^4\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

\(^5\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

\(^6\) A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.
TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_{i} is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_{i} is the impact of the Transmission Reliability Margin on the Flowgate during that period.

Postbacks_{Fi} are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{Fi} are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

\[
AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows
\]

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NFi} are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NFi} are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.
R11. When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [Violation Risk Factor: To Be Determined] [Time Horizon: Operations Planning]

\[
\text{ATC} = \min(P)
\]

\[
P = \{\text{PATC}_1, \text{PATC}_2, \ldots, \text{PATC}_n\}
\]

\[
\text{PATC}_n = \frac{\text{AFC}_n}{\text{DF}_{np}}
\]

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

PATC<sub>n</sub> is the partial Available Transfer Capability for a path relative to a Flowgate <i>n</i>.

AFC<sub>n</sub> is the Available Flowgate Capability of a Flowgate <i>n</i>.

DF<sub>np</sub> is the distribution factor for Flowgate <i>n</i> relative to path <i>p</i>.

C. Measures

M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

M5. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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7 A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.
M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator’s models in calculating AFC. (R5.1)

M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

M13. The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the
value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

### D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority**

       Regional Entity.

   1.2. **Compliance Monitoring Period and Reset Time Frame**

       Not applicable.

   1.3. **Data Retention**

       The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

       - The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
       - The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
       - The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
       - The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
       - The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
       - The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
       - The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
       - If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

       The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

   1.4. **Compliance Monitoring and Enforcement Processes:**
The following processes may be used:
- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information
None.
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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</thead>
<tbody>
<tr>
<td>R1.</td>
<td>The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.</td>
<td>The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.</td>
<td>The Transmission Service Provider does not include in its ATCID the information described in R1.1. <strong>OR</strong> The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).</td>
<td>The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).</td>
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</table>
| R2. | One or more of the following:  
- The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.  
- The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.  
- The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not been more than 14 days | One or more of the following:  
- The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.  
- The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.  
- The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.  
- The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.  
- The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.  
- The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.  
- The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.  
- The Transmission Operator did not establish its list of Flowgates more than nine months late as described in R2.2.  
- The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. | One or more of the following:  
- The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.  
- The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.  
- The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.  
- The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. |
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<tr>
<td></td>
<td>since the notification (R2.5.1)</td>
<td>has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</td>
<td>has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</td>
<td>R2.3.</td>
</tr>
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<td></td>
<td>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but it has not been more than 14 days (two weeks) since their determination.</td>
<td>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</td>
<td>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</td>
<td>• The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</td>
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<td>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but it has not been more than 21 days (three weeks) since their determination.</td>
<td>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but it has not been more than 28 days (four weeks) since their determination.</td>
<td>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</td>
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<td>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</td>
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<td>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</td>
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<td>• The Transmission Operator did not provide its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</td>
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<td>R #</td>
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</table>
| R3. | One or more of the following:  
- The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.  
- The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days  
- The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:  
- The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.  
- The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days  
- The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:  
- The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.  
- The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days  
- The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:  
- The Transmission Operator did not update the model per R3.2 for more than 4 calendar days  
- The Transmission Operator did not update the model for per R3.3 for more than ten weeks  
- The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.  
- The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.  
- The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area. |
<p>| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or |</p>
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<td>5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..</td>
<td>10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..</td>
<td>15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..</td>
<td>more than 3 reservations, whichever is greater..</td>
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| R5.  | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATC-ID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATC-ID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATC-ID. | One or more of the following:  
  - The Transmission Service Provider did not use the model provided by the Transmission Operator.  
  - The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATC-ID.  
  - The Transmission Service Provider did not use AFC provided by a third party. |
<p>| R6.  | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |</p>
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<tr>
<td>R7.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
<td>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</td>
</tr>
<tr>
<td>R8.</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).</td>
</tr>
<tr>
<td>R9.</td>
<td>The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but</td>
<td>The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates.</td>
<td>The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all.</td>
<td>The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all.</td>
</tr>
<tr>
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<tr>
<td></td>
<td>not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).</td>
<td>or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).</td>
<td>Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).</td>
<td>Flowgates or more than 3 Flowgates (whichever is greater).</td>
</tr>
</tbody>
</table>
| R10 | One or more of the following:  
- For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.  
- For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.  
- For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | One or more of the following:  
- For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.  
- For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.  
- For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | One or more of the following:  
- For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.  
- For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.  
- For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | One or more of the following:  
- For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.  
- For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.  
- For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
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<td>R11.</td>
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<td>N/A</td>
<td>The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.</td>
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A. Regional Differences

None identified.

B. Associated Documents

Version History

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<td>Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11</td>
<td>Revised</td>
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A. Introduction

1. Title: Nuclear Plant Interface Coordination
2. Number: NUC-001-2
3. Purpose: This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
4. Applicability:
   4.1. Nuclear Plant Generator Operator.
   4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
      4.2.1 Transmission Operators.
      4.2.2 Transmission Owners.
      4.2.3 Transmission Planners.
      4.2.4 Transmission Service Providers.
      4.2.5 Balancing Authorities.
      4.2.6 Reliability Coordinators.
      4.2.7 Planning Coordinators.
      4.2.8 Distribution Providers.
      4.2.9 Load-serving Entities.
      4.2.10 Generator Owners.
      4.2.11 Generator Operators.
5. Effective Date: April 1, 2010

B. Requirements

R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [Risk Factor: Lower]

R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements\(^1\) that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [Risk Factor: Medium]

R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [Risk Factor: Medium]

R4. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [Risk Factor: High]

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\(^1\) Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.
R4.1. Incorporate the NPIRs into their operating analyses of the electric system.
R4.2. Operate the electric system to meet the NPIRs.
R4.3. Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.

R5. The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [Risk Factor: High]

R6. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [Risk Factor: Medium]

R7. Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [Risk Factor: High]

R8. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [Risk Factor: High]

R9. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [Risk Factor: Medium]

R9.1. Administrative elements:

R9.1.1. Definitions of key terms used in the agreement.
R9.1.2. Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.
R9.1.3. A requirement to review the agreement(s) at least every three years.
R9.1.4. A dispute resolution mechanism.

R9.2. Technical requirements and analysis:

R9.2.1. Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
R9.2.2. Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
R9.2.3. Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.

R9.3. Operations and maintenance coordination:

R9.3.1. Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
R9.3.2. Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
R9.3.3. Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.

R9.3.4. Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.

R9.3.5. Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.

R9.3.6. Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity’s plan.

R9.3.7. Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.

R9.4. Communications and training:

R9.4.1. Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.

R9.4.2. Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.

R9.4.3. Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.

R9.4.4. Provisions for supplying information necessary to report to government agencies, as related to NPIRs.

R9.4.5. Provisions for personnel training, as related to NPIRs.

C. Measures

M1. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)

M2. The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

M3. Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)

M4. Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
M4.1 The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)

M4.2 The electric system was operated to meet the NPIRs. (Requirement 4.2)

M4.3 The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)

M5. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)

M6. The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)

M7. The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)

M8. The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority
Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame
Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:
   Compliance Audits
   Self-Certifications
   Spot Checking
   Compliance Violation Investigations
   Self-Reporting
   Complaints

1.4. Data Retention
The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
   - For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
• For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.

• For Measure 3, the Transmission Entity shall have the latest planning analysis results.

• For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.

• For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

2.1. Lower: Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.

2.2. Moderate: Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.

2.3. High: One or more requirements of R3 through R8 were not met.

2.4. Severe: No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs. Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

F. Associated Documents

**Version History**

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<td>2</td>
<td>January 22, 2010</td>
<td>Approved by FERC on January 21, 2010</td>
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and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.
A. Introduction

1. Title: Operating Personnel Responsibility and Authority
2. Number: PER-001-0.1
3. Purpose: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. Applicability
   4.1. Transmission Operators.
   4.2. Balancing Authorities.

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.
1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

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A. Introduction

1. Title: Operating Personnel Responsibility and Authority
2. Number: PER-001-0
3. Purpose: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. Applicability
   4.1. Transmission Operators.
   4.2. Balancing Authorities.

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

   M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

   M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

   M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

   M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

   Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.
1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

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</table>
A. Introduction

1. Title: Operating Personnel Training

2. Number: PER-002-0

3. Purpose: Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.

4. Applicability

   4.1. Balancing Authority.

   4.2. Transmission Operator.

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.

R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:

   R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

   R2.2. Positions directly responsible for complying with NERC standards.

R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:

   R3.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.

   R3.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.

   R3.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.

   R3.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.

R4. For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

C. Measures

M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.
D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

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A. Introduction

1. **Title:** Operating Personnel Credentials
2. **Number:** PER-003-0
3. **Purpose:** Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.

4. **Applicability**
   4.1. Transmission Operators.
   4.2. Balancing Authorities.
   4.3. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:

   R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

   R1.2. Positions directly responsible for complying with NERC standards.

C. Measures

M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified operating personnel on shift in required positions at all times with the following exceptions:

   M1.1 While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.

   M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review will be conducted every three years. Staffing schedules and certification numbers will be compared to ensure that positions that require NERC-certified operating personnel were covered as required. Certification numbers from the Transmission Operator, Balancing Authority, and Reliability Coordinator will be compared with NERC records.

   Exception Reporting: Any violation of the standard must be reported to the Regional Reliability Organization, who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.

   1.1. **Compliance Monitoring Responsibility**

      Regional Reliability Organization.
1.2. Compliance Monitoring Period and Reset Timeframe
   One calendar month without a violation.

1.3. Data Retention
   Present calendar year plus previous calendar year staffing plan.

1.4. Additional Compliance Information
   Not specified.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.

2.2. Level 2: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.

2.3. Level 3: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.

2.4. Level 4: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.

E. Regional Differences
   None identified.

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Adopted by NERC Board of Trustees: February 8, 2005
Effective Date: April 1, 2005
A. Introduction

1. **Title:** Reliability Coordination — Staffing
2. **Number:** PER-004-1
3. **Purpose:**
   Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.
4. **Applicability**
   4.1. Reliability Coordinators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

R3. Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.

R4. Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

R5. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request training records that confirm that each of its operating personnel has completed a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel, as specified in Requirement 2.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to, a documented training program and individual training records for each of its operating personnel or other equivalent evidence that will be used to confirm that it meets Requirements 3 and 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 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 Reliability Coordinator shall keep evidence of compliance for the previous two calendar years plus the current year.

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:** Not applicable.

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 its shift operating personnel did not complete a minimum of five days per year of training and drills using realistic simulations of system emergencies in the past year. (R2)

2.4.2 No evidence operating personnel have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas. (R3)

2.4.3 No evidence operating personnel have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area. (R4)

E. Regional Differences

1. None identified.

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<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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A. Introduction

1. Title: Reliability Coordination — Staffing
2. Number: PER-004-2
3. Purpose:
   Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.
4. Applicability
   4.1. Reliability Coordinators.
5. Effective Date:
   - Retire Requirement 2 when PER-005-1 Requirement 3 becomes effective.
   - Retire Requirements 3 and 4 when PER-005-1 Requirements 1 and 2 become effective.

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

None

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 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 Reliability Coordinator shall keep evidence of compliance for the previous
two calendar years plus the current year.

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 (Replaced with VSLs)**

2.1.

**E. Regional Differences**

None identified.

**Version History**

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<td>Retire R2 and M1 when PER-005-1 Requirement 3 becomes effective. Retire R3, R4 and M2 when PER-005 R1 and R2 become effective.</td>
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A. Introduction

1. Title: System Personnel Training
2. Number: PER-005-1
3. Purpose: To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System.
4. Applicability:
   4.1. Functional Entities:
      4.1.1 Reliability Coordinator.
      4.1.2 Balancing Authority.
      4.1.3 Transmission Operator.

5. Proposed Effective Date for Regulatory Approvals:
   5.1. In those jurisdictions where regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.
   5.2. In those jurisdictions where regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after Board of Trustees adoption.
   5.3. In those jurisdictions where regulatory approval is required Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program.
   [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

   R1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators.

   R1.1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for inclusion in training.
R1.2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1.

R1.3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.

R1.4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.

R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator’s capabilities to perform each assigned task identified in R1.1 at least one time. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

R2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator’s capabilities to perform the new or modified tasks.

R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.

C. Measures

M1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its company-specific reliability-related task list, with the date of the last review and/or revision, as specified in R1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its learning objectives and training materials, as specified in R1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered and the dates of delivery to show that it delivered the training, as specified in R1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal...
audit results) that it performed an annual training program evaluation, as specified in R1.4

M2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence to show that it verified that each of its System Operators is capable of performing each assigned task identified in R1.1, as specified in R2. This evidence can be documents such as training records showing successful completion of tasks with the employee name and date; supervisor check sheets showing the employee name, date, and task completed; or the results of learning assessments.

M3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence to show that each System Operator has obtained 32 hours of emergency operations training, as specified in R3.

M3.1 Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence to show that each System Operator received emergency operations training using simulation technology, as specified in R3.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring Period and Reset

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Data Retention

Each Reliability Coordinator, Balancing Authority and Transmission Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority and Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.
### 2. Violation Severity Levels

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<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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<tr>
<td>R1</td>
<td>None</td>
<td>The responsible entity failed to provide evidence that it updated its company-specific reliability-related task list to identify new or modified tasks each calendar year (R1.1.1) OR The responsible entity failed to provide evidence of evaluating its training program to identify needed changes to its training program(s). (R1.4)</td>
<td>The responsible entity failed to design and develop learning objectives and training materials based on the BES company specific reliability related tasks. (R1.2)</td>
<td>The responsible entity failed to prepare a company-specific reliability-related task list (R1.1.1) OR The responsible entity failed to deliver training based on the BES company specific reliability related tasks. (R1.3)</td>
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<td>R2</td>
<td>None</td>
<td>The responsible entity verified at least 90% but less than 100% of its System Operators’ capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)</td>
<td>The responsible entity verified at least 70% but less than 90% of its System Operators’ capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks (R2) OR The responsible entity failed to verify its system operator’s capabilities to perform each new or modified task within six months of making a modification to its BES company-specific reliability-related task list. (R2.1)</td>
<td>The responsible entity verified less than 70% of its System Operators’ capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)</td>
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<td>R3</td>
<td>None</td>
<td>The responsible entity provided at least 32 hours of emergency operations training to at least 90% but less than 100% of their System Operators. (R3)</td>
<td>The responsible entity provided at least 32 hours of emergency operations training to at least 70% but less than 90% of its System Operators. (R3)</td>
<td>The responsible entity provided 32 hours of emergency operations training to less than 70% of its System Operators (R3) OR The responsible entity did not include simulation technology replicating the operational behavior of the BES in its emergency operations training. (R3.1)</td>
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E. Regional Variances

None.

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A. Introduction

1. Title: System Protection Coordination
2. Number: PRC-001-1
3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities
4.2. Transmission Operators
4.3. Generator Operators

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator’s protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators’ protection systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

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 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 Generator Operator and Transmission Operator shall have current, in-force
documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of
historical data (evidence) for Measures 2 and 3.

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 Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new
protective systems and all protective system changes with its Transmission
Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

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 Failed to provide evidence of coordination when installing new protective
systems and all protective system changes with neighboring Transmission
Operators and Balancing Authorities as specified in R3.2.
3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

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<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
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A. Introduction

1. Title: Define Regional Disturbance Monitoring and Reporting Requirements
2. Number: PRC-002-1
3. Purpose: Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.

4. Applicability
   4.1. Regional Reliability Organization.

5. Effective Date: Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:
   R1.1. Location, monitoring and recording requirements, including the following:
      R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
      R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:
   R2.1. Location, monitoring and recording requirements, including the following:
      R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
      R2.1.2. Elements to be monitored at each location.
      R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:
         R2.1.3.1. Three phase to neutral voltages.
         R2.1.3.2. Three phase currents and neutral currents.
         R2.1.3.3. Polarizing currents and voltages, if used.
         R2.1.3.4. Frequency.
         R2.1.3.5. Megawatts and megavars.
   R2.2. Technical requirements, including the following:
      R2.2.1. Recording duration requirements.
      R2.2.2. Minimum sampling rate of 16 samples per cycle.
      R2.2.3. Event triggering requirements.
R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

   R3.1.1. Criteria for equipment location giving consideration to the following:
            - Site(s) in or near major load centers
            - Site(s) in or near major generation clusters
            - Site(s) in or near major voltage sensitive areas
            - Site(s) on both sides of major transmission interfaces
            - A major transmission junction
            - Elements associated with Interconnection Reliability Operating Limits
            - Major EHV interconnections between control areas
            - Coordination with neighboring regions within the interconnection

   R3.1.2. Elements and number of phases to be monitored at each location.

   R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

            R3.1.3.1. Voltage, current and frequency.
            R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:


   R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

   R4.1. Criteria for events that require the collection of data from DMEs.

   R4.2. List of entities that must be provided with recorded Disturbance data.

   R4.3. Timetable for response to data request.

   R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE\(^1\) analysis tool,

   R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files\(^2\).

   R4.6. Data content requirements and guidelines.

---

\(^1\) IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

\(^2\) Compliance with this requirement is not effective until the IEEE Standard is approved.
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization’s requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.

M2. The Regional Reliability Organization’s Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

       NERC.

   1.2. Compliance Monitoring Period and Reset Time Frame

       One calendar year.

   1.3. Data Retention

       The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

       The Compliance Monitor will retain its audit data for three years.

   1.4. Additional Compliance Information

       The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. Levels of Non-Compliance

   2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

       2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

       2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

   2.2. Level 2: There shall be a level two non-compliance if any of the following conditions exist:

       2.2.1 Technical requirements were not specified for one or more types of DMEs.
2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. **Regional Differences**

None identified.

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</table>
A. Introduction

1. Title: Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems
2. Number: PRC-003-1
3. Purpose: To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. Applicability
   4.1. Regional Reliability Organization
5. Effective Date: May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:
   R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).
   R1.2. Data reporting requirements (periodicity and format) for Misoperations.
   R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.
   R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.
M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.
M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. Compliance Monitoring Process
1.1. **Compliance Monitoring Responsibility**

NERC.

1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.

1.3. **Data Retention**

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. **Additional Compliance Information**

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

2.1. **Level 1:** Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. **Level 2:** Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. **Level 3:** Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. **Level 4:** There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. **Regional Differences**

None identified.

**Version History**

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<th>Version</th>
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| 1       | December 1, 2005| 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”  
          |                 | 2. Added “periods” to items where appropriate.  
          |                 | 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.               | 01/20/06        |
A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   4.1. Transmission Owner.
   4.2. Distribution Provider that owns a transmission Protection System.
   4.3. Generator Owner.
5. **Effective Date:** August 1, 2006

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. Compliance Monitoring Process
1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame
One calendar year.

1.3. Data Retention
The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information
The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences
None identified.
### Version History

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             |                    | Changed “Timeframe” to “Time Frame” in item D, 1.2.                  | 01/20/06         |
Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 21, 2007</td>
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<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 29, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 23, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
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2 Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1. PRC-004-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-001-1 and PRC-STD-003-1 were approved as NERC reliability standards. The new standard addresses the following areas:

1. Requirements for investigating operations to check for Misoperations.
2. Mitigation requirements after security-based Misoperations for redundant or non-redundant Protection Systems or Remedial Action Schemes.
3. Mitigation requirements after dependability-based Misoperations that do not adversely affect the reliability of the Bulk Electric System.

Several significant changes were made to PRC-STD-001 and PRC-STD-003 and they are itemized here:

1. PRC-STD-003 was renumbered to PRC-004-WECC-1. This makes both the PRC-004 and the Regional PRC-004-WECC-1 standards applicable to similar entities. PRC-003 is applicable to the RRO.

2. Standard PRC-STD-001 will be retracted because the requirements are covered by other standards per description below:

   a. PRC-STD-001 requirements B-WR1-a,b,c are covered under PRC-001
b. PRC-STD-001 requirement B-WR1-d is covered in this standard PRC-004-WECC-1

c. PRC-STD-001 requirement B-WR1-e is covered under TOP-005-1

The WECC Operating Committee approved the PRC-004-WECC-1 standard as a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1 on March 6, 2008. This posting of the standard is for ballot by the WECC Board of Directors. The Operating Committee recommends that the WECC Board of Directors approve the PRC-004-WECC-1 as a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1. In addition, the Operating Committee recommends that the WECC Board of Directors submit the standard to the NERC and FERC for approval.

The tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS)” are included with this draft standard for reference only. With the final standard posting, links will be provided to tables on the WECC website in the WECC libraries at [http://www.wecc.biz/documents/library...](http://www.wecc.biz/documents/library...)

**Justification for a Regional Standard**

The NERC standard PRC-003-1 has requirements for Regional Reliability Organizations to establish procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations but does not address the owners of the transmission and generation facilities. The NERC standard PRC-004-1 has requirements for Protection System Misoperations but does not provide for the additional requirements as listed in PRC-004-WECC-1. The WECC Transmission Paths listed in the table titled “Major WECC Transfer Paths in the Bulk Electric System” and WECC RAS listed in table titled “Major WECC Remedial Action Schemes (RAS)” of PRC-004-WECC-1 are significant components for reliable delivery of power in the Western Interconnection. Protection System Misoperations and failures can cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers. WECC identified the need for the timely mitigation of relaying problems and implemented such actions under the Reliability Management System (RMS). PRC-004-WECC-1 incorporates the RMS criteria and provides:

1. More robust requirements for review and analysis of all operations of those elements by operating and system protection personnel, and
2. Timely actions that must be taken to ensure that Misoperations of those elements are not repeated.

This standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.
**Future Development Plan:**

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<td>April 16-18, 2008</td>
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<tr>
<td>3. Drafting Team to review and respond to industry comments</td>
<td>May 2008</td>
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<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
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<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

Functionally Equivalent Protection System (FEPS): A Protection System that provides performance as follows:

- Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards.
- Each Protection System may have different components and operating characteristics.

Functionally Equivalent RAS (FERAS): A Remedial Action Scheme (RAS) that provides the same performance as follows:

- Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards.
- Each RAS may have different components and operating characteristics.

Security-Based Misoperation: A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device’s certainty not to operate falsely.

Dependability-Based Misoperation: Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device’s certainty to operate when required.
Introduction

1. Title: Protection System and Remedial Action Scheme Misoperation

2. Number: PRC-004-WECC-1

3. Purpose: Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

   4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at (http://www.wecc.biz/documents/library) and “Major WECC Remedial Action Schemes (RAS)” provided at (http://www.wecc.biz/documents/library)

   4.2. Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at (http://www.wecc.biz/documents/library)

   4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at (http://www.wecc.biz/documents/library) and “Major WECC Remedial Action Schemes (RAS)” provided at (http://www.wecc.biz/documents/library)

5. Effective Date: On the first day of the second quarter following applicable regulatory approval.

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]

   R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.

   R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
R2. Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

R2.1. If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners’ and Generator Owners’ discretion. [Violation Risk Factor: High] [Time Horizon: Same-day Operations]

R2.2. If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. [Violation Risk Factor: High] [Time Horizon: Same-day Operations]

R2.2.1. Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

R2.2.2. The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

R2.3. If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the
R2.3.1. When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

R2.3.2. When FERAS is not available, then

2.3.2.1. The Generator Owners shall adjust generation to a reliable operating level, or

2.3.2.2. Transmission Operators shall adjust the SOL and operate the facilities within established limits.

R2.4. If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

R2.4.1. Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

R2.4.2. Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]

R.3. Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]

R3.1. Identification of a Misoperation of a Protection System and/or RAS,

R3.2. Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

M2. Transmission Owners and Generation Owners shall have evidence for the following.

M2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2 Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

M2.2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2.2 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

M2.3 The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

M2.3.1 The Transmission Owner shall have evidence that it removed the associated Element from service.

M2.3.2 The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

M2.4 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that
misoperated including documentation that describes the actions taken.

**M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1** **Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2** **Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3** **Data Retention**
1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

<table>
<thead>
<tr>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.</td>
<td>System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.</td>
<td>System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.</td>
<td>System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.</td>
</tr>
</tbody>
</table>

R2.1 and R2.2.1

<table>
<thead>
<tr>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.</td>
<td>The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.</td>
<td>The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.</td>
<td>The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.</td>
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</table>
## R2.3

<table>
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</thead>
<tbody>
<tr>
<td>The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.</td>
<td>The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.</td>
<td>The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.</td>
<td>The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.</td>
</tr>
</tbody>
</table>

## R2.2.2 and R2.4

<table>
<thead>
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<th>Lower</th>
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</tr>
</thead>
<tbody>
<tr>
<td>The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.</td>
<td>The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.</td>
<td>The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.</td>
<td>The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.</td>
</tr>
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R3.1

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<th>Severe</th>
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</thead>
<tbody>
<tr>
<td>The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.</td>
</tr>
</tbody>
</table>

R3.2

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<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.</td>
<td>The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.</td>
</tr>
</tbody>
</table>

Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
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<tbody>
<tr>
<td>1</td>
<td>January 1, 2008</td>
<td>Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1</td>
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### Major WECC Transfer Paths in the Bulk Electric System
(Revised September 19, 2007)

<table>
<thead>
<tr>
<th>PATH NAME</th>
<th>Path Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>1</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>3</td>
</tr>
<tr>
<td>3. West of Cascades – North</td>
<td>4</td>
</tr>
<tr>
<td>4. West of Cascades – South</td>
<td>5</td>
</tr>
<tr>
<td>5. West of Hatwai</td>
<td>6</td>
</tr>
<tr>
<td>6. Montana to Northwest</td>
<td>8</td>
</tr>
<tr>
<td>7. Idaho to Northwest</td>
<td>14</td>
</tr>
<tr>
<td>8. South of Los Banos or Midway - Los Banos</td>
<td>15</td>
</tr>
<tr>
<td>9. Idaho – Sierra</td>
<td>16</td>
</tr>
<tr>
<td>10. Borah West</td>
<td>17</td>
</tr>
<tr>
<td>11. Idaho – Montana</td>
<td>18</td>
</tr>
<tr>
<td>12. Bridger West</td>
<td>19</td>
</tr>
<tr>
<td>13. Path C</td>
<td>20</td>
</tr>
<tr>
<td>14. Southwest of Four Corners</td>
<td>22</td>
</tr>
<tr>
<td>15. PG&amp;E – SPP</td>
<td>24</td>
</tr>
<tr>
<td>16. Northern – Southern California</td>
<td>26</td>
</tr>
<tr>
<td>17. Intermtn. Power Project DC Line</td>
<td>27</td>
</tr>
<tr>
<td>18. TOT 1A</td>
<td>30</td>
</tr>
<tr>
<td>19. TOT 2A</td>
<td>31</td>
</tr>
<tr>
<td>20. Pavant – Gonder 230 kV</td>
<td>32</td>
</tr>
<tr>
<td>Intermountain – Gonder 230 kV</td>
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</tr>
<tr>
<td>21. TOT 2B</td>
<td>34</td>
</tr>
<tr>
<td>22. TOT 2C</td>
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<tr>
<td>23. TOT 3</td>
<td>36</td>
</tr>
<tr>
<td>24. TOT 5</td>
<td>39</td>
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<tr>
<td>25. SDGE – CFE</td>
<td>45</td>
</tr>
<tr>
<td>26. West of Colorado River (WOR)</td>
<td>46</td>
</tr>
<tr>
<td>27. Southern New Mexico (NM1)</td>
<td>47</td>
</tr>
<tr>
<td>28. Northern New Mexico (NM2)</td>
<td>48</td>
</tr>
<tr>
<td>29. East of the Colorado River (EOR)</td>
<td>49</td>
</tr>
<tr>
<td>30. Cholla – Pinnacle Peak</td>
<td>50</td>
</tr>
<tr>
<td>31. Southern Navaio</td>
<td>51</td>
</tr>
<tr>
<td>32. Brownlee East</td>
<td>55</td>
</tr>
<tr>
<td>33. Lugo – Victorville 500 kV</td>
<td>61</td>
</tr>
<tr>
<td>34. Pacific DC Intertie</td>
<td>65</td>
</tr>
<tr>
<td>35. COI</td>
<td>66</td>
</tr>
<tr>
<td>36. North of John Day cutplane</td>
<td>73</td>
</tr>
<tr>
<td>37. Alturas</td>
<td>76</td>
</tr>
<tr>
<td>38. Montana Southeast</td>
<td>80</td>
</tr>
<tr>
<td>39. SCIT**</td>
<td></td>
</tr>
<tr>
<td>40. COI/PDCI – North of John Day cutplane**</td>
<td></td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
<table>
<thead>
<tr>
<th>Path Name*</th>
<th>Path</th>
<th>RAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>Path 1</td>
<td>Remedial actions are required to achieve the rated transfer capability. Most involve tripping tie lines for outages in the BCTC system. East to West: For high transfers, generation tripping is required north of the SOK cutplane in Alberta.</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>Path 3</td>
<td>Generator and reactive tripping in the BCTC system to protect against the impact caused by various contingencies during transfers between British Columbia and the Northwest.</td>
</tr>
<tr>
<td>3. West of Hatwai</td>
<td>Path 6</td>
<td>Generator dropping (Libby, Noxon, Lancaster, Dworshak); Reactor tripping (Garrison); Tripping of Miles City DC link.</td>
</tr>
<tr>
<td>4. Montana to Northwest</td>
<td>Path 8</td>
<td>Tripping Colstrip by ATR (NWMT); Switching shunt reactors at Garrison 500 kV; Tripping the back-to-back DC tie at Miles City; Tripping Libby, and Noxon generation by WM-RAS (BPA).</td>
</tr>
<tr>
<td>5. Idaho to Northwest</td>
<td>Path 14</td>
<td>Generator Runback at Hells Canyon; Jim Bridger tripping for loss of Midpoint – Summer Lake 500 kV line.</td>
</tr>
<tr>
<td>7. Idaho Sierra</td>
<td>Path 16</td>
<td>Automatic load shedding is required when the Alturas line is open for loss of the Midpoint-Humbolt 345 kV line during high Sierra system imports.</td>
</tr>
<tr>
<td>8. Bridger West</td>
<td>Path 19</td>
<td>Jim Bridger tripping for delayed clearing and multi-line faults; Addition of shunt capacitors at Jim Bridger, Kinport and Goshen and series capacitor bypassing at Burns.</td>
</tr>
<tr>
<td>9. IPP DC Line</td>
<td>Path 27</td>
<td>IPP Contingency Arming System trips one or two IPP generating units.</td>
</tr>
<tr>
<td>10. TOT1A</td>
<td>Path 30</td>
<td>Bonanza and Flaming Gorge generation is tripped for loss of the Bonanza-Mona 345 kV line to achieve rating on TOT1A.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11.</td>
<td>TOT2A</td>
<td>Path 31 For the Montrose-Hesperus 345 kV line outage with Nucla generation above 60 MW, the parallel Montrose-Nucla 115 kV line is automatically transfer tripped.</td>
</tr>
<tr>
<td>12.</td>
<td>TOT2B</td>
<td>Path 34 Trip Huntington generation for loss of the Huntington-Pinto + Four Corners lines when parallel lines are heavily loaded.</td>
</tr>
<tr>
<td>13.</td>
<td>TOT5</td>
<td>Path 39 For an outage of the Hayden-Gore Pass 230 kV line, the lower voltage parallel path is tripped.</td>
</tr>
<tr>
<td>14.</td>
<td>SDGE RAS</td>
<td>Path 44 RAS used to meet reactive margin criteria for loss of both San Onofre units.</td>
</tr>
<tr>
<td>15.</td>
<td>SDGE – CFE</td>
<td>Path 45 The purpose of the RAS is to automatically cross-trip (transfer trip) the Miguel – Tijuana 230kV following the outage of Imperial Valley – Miguel 500kV line.</td>
</tr>
<tr>
<td>16.</td>
<td>Southern New Mexico</td>
<td>Path 47 For double contingencies on the 345 kV lines defined in the path, WECC Operating Procedure EPE-1 is implemented.</td>
</tr>
<tr>
<td>17.</td>
<td>Pacific DC Intertie</td>
<td>Path 65 Northwest generator tripping; Series capacitor fast insertion; mechanically switched shunt capacitors</td>
</tr>
<tr>
<td>18.</td>
<td>California – Oregon Intertie</td>
<td>Path 66 Northwest generator tripping; Chief Jo Brake insertion; Fort Rock Series Capacitor insertion; Northern California generator and pump load tripping; N. California series capacitor bypassing, shunt reactor or capacitor insertion; Initiation of NE\SE Separation Scheme at Four Corners.</td>
</tr>
<tr>
<td>19.</td>
<td>Meridian 500/230 kV Transformers**</td>
<td>Following the loss of the Meridian 500/230kV transformers, RAS is used to comply with WECC Standards under high load conditions.</td>
</tr>
<tr>
<td>20.</td>
<td>Northern-Southern California</td>
<td>Path 26 Remedial action required to achieve the rated transfer capability. Midway area generation tripped for loss of any two of three Midway-Vincent 500 kV lines.</td>
</tr>
<tr>
<td>21.</td>
<td>PNM Import Contingency Load Shedding Scheme (ICLSS)</td>
<td>Path 48 ICLSS is a centralized load shedding scheme for low probability events such as simultaneous outage of the Four Corners-West Mesa (FW) 345 kV and San Juan-B-A (WW) 345 kV lines, as well as any unplanned disturbance affecting voltage in the Northern New Mexico transmission system.</td>
</tr>
<tr>
<td></td>
<td>Description</td>
<td>Notes</td>
</tr>
<tr>
<td>---</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>22.</td>
<td>Valley Direct Load Trip (DLT)</td>
<td>RAS is required for the loss of the Serrano-Valley 500 kV line. About 200 MW of Valley load is tripped.</td>
</tr>
<tr>
<td>23.</td>
<td>South of Lugo N-2 RAS</td>
<td>RAS is required for the simultaneous double line outage of any combination of the Lugo-Mira Loma 1 (when looped), 2, and 3 500 kV lines and the Lugo-Serrano (when de-looped) 500 kV line.</td>
</tr>
<tr>
<td>24.</td>
<td>Lower Snake RAS</td>
<td>The RAS is required to protect for the double line outage of the Lower Monumental-Little Goose 500-kV lines.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Generation is dropped at Little Goose and Lower Granite Powerhouses as well as key the WM RAS. An outage of the Little Goose – Lower Granite 500 kV lines will drop generation at Lower Granite Powerhouse and key the Western Montana RAS.</td>
</tr>
<tr>
<td>25.</td>
<td>Palo Verde – COI Mitigation Scheme</td>
<td>Path 66 Required to provide for safe operation of the COI for the loss of two units at Palo Verde Nuclear Generating Station (PVNGS). The RAS protects the PVNGS and Palo Verde Transmission System (PVTS) for faults at Palo Verde and subsequent outage of the Palo Verde – Westwing 500 kV lines.</td>
</tr>
<tr>
<td>26.</td>
<td>Palo Verde/Hassayampa RAS</td>
<td>Provides protection to the PVNGS and the PVTS for faults at Palo Verde and subsequent double line outage of the Palo Verde to Westwing 500 kV lines.***</td>
</tr>
<tr>
<td>27.</td>
<td>Sierra Pacific – PacifiCorp RAS</td>
<td>Path 76 Needed for loss of the 230 kV Malin-Hilltop line when heavily loaded unless automatic reclose is successful. The scheme closes the Hilltop 345 kV line reactor if pre-outage northbound flow is greater than 150 MW. For pre-outage southbound flow greater than 235 MW the Hilltop 345 kV line trips and the Hilltop 345 kV line reactors closes.***</td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The Meridian 500/230 kV transformers are not included in the Path Rating Catalog. The RAS associated with the Meridian transformers is included in Table 3 because the failure of the RAS may result in cascading.

*** The Palo Verde/Hassayampa RAS is designed to prevent cascading problems throughout the WECC region. This scheme is not Path related and is not used to protect any specific WECC Path.
A. Introduction

1. Title: Transmission and Generation Protection System Maintenance and Testing

2. Number: PRC-005-1

3. Purpose: To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. Applicability
   4.1. Transmission Owner.
   4.2. Generator Owner.
   4.3. Distribution Provider that owns a transmission Protection System.

5. Effective Date: May 1, 2006

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
   R1.1. Maintenance and testing intervals and their basis.
   R1.2. Summary of maintenance and testing procedures.

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
   R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.
   R2.2. Date each Protection System device was last tested/maintained.

C. Measures

M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization.
1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.

1.3. **Data Retention**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. **Additional Compliance Information**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, 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 of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. **Level 2:** Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. **Level 3:** Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. **Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

None identified.

**Version History**

<table>
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A. Introduction

1. **Title:** Development and Documentation of Regional Reliability Organizations’ Underfrequency Load Shedding Programs
2. **Number:** PRC-006-0
3. **Purpose:** Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.
4. **Applicability:**
   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:
   
   R1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.

   R1.2. Design details shall include, but are not limited to:
      
      R1.2.1. Frequency set points.
      R1.2.2. Size of corresponding load shedding blocks (% of connected loads.)
      R1.2.3. Intentional and total tripping time delays.
      R1.2.4. Generation protection.
      R1.2.5. Tie tripping schemes.
      R1.2.6. Islanding schemes.
      R1.2.7. Automatic load restoration schemes.
      R1.2.8. Any other schemes that are part of or impact the UFLS programs.

   R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

   R1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:
      
      R1.4.1. A review of the frequency set points and timing, and
      R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.

R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).
R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.

M3. The Regional Reliability Organization shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days) for the program, database, and results of assessments.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation demonstrating the coordination of the Regional Reliability Organization’s UFLS program was incomplete in one of the elements in Reliability Standard PRC-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation demonstrating the coordination of the Regional Reliability Organization’s UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional Reliability Organization’s UFLS program was not provided, or an assessment was not completed in the last five years.
E. Regional Differences

1. None identified.

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A. Introduction
1. Title: Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization’s Underfrequency Load Shedding Program Requirements
2. Number: PRC-007-0
3. Purpose: Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.
4. Applicability:
   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program
   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program
   4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program
   4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program
5. Effective Date: April 1, 2005

B. Requirements
R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization’s UFLS program requirements.
R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.
R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

C. Measures
M1. Each Transmission Owner’s and Distribution Provider’s UFLS program shall be consistent with its associated Regional Reliability Organization’s UFLS program requirements.
M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 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 Timeframe
   On request (within 30 calendar days).

1.3. Data Retention
   None specified.

1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance

2.1. Level 1: The evaluation of the entity’s UFLS program for consistency with its Regional Reliability Organization’s UFLS program is incomplete or inconsistent in one or more requirements of Reliability Standard PRC-006-0_R1, but is consistent with the required amount of Load shedding.

2.2. Level 2: The amount of Load shedding is less than 95 percent of the Regional requirement in any of the Load steps.

2.3. Level 3: The amount of Load shedding is less than 90 percent of the Regional requirement in any of the Load steps.

2.4. Level 4: The evaluation of the entity’s UFLS program for consistency with its Regional Reliability Organization’s UFLS program was not provided or the amount of Load shedding is less than 85 percent of the Regional requirement on any of the Load steps.

E. Regional Differences

1. None identified.

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A. Introduction

1. Title: Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
2. Number: PRC-008-0
3. Purpose: Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.
4. Applicability:
   4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program
   4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program
5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner’s and Distribution Provider’s UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program’s implementation to its Regional Reliability Organization and NERC on request (within 30 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 Timeframe
       On request (within 30 calendar days).
   1.3. Data Retention
       None specified.
   1.4. Additional Compliance Information
       None.
2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation was not provided.

E. Regional Differences

1. None identified.

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A. Introduction

1. **Title:** Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event

2. **Number:** PRC-009-0

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**
   - 4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program
   - 4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program
   - 4.3. Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program
   - 4.4. Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization’s UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:
   - R1.1. A description of the event including initiating conditions.
   - R1.2. A review of the UFLS set points and tripping times.
   - R1.3. A simulation of the event.
   - R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

C. Measures

M1. Each Transmission Owner’s, Transmission Operator’s, Load-Serving Entity’s and Distribution Provider’s documentation of the UFLS program performance following an underfrequency event includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. Each Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.
D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility
   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe
   On request 90 calendar days after the system event.

   1.3. Data Retention
   None specified.

   1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance

   2.1. Level 1: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more elements in Reliability Standard PRC-009-0_R1.

   2.2. Level 2: Not applicable.

   2.3. Level 3: Not applicable.

   2.4. Level 4: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

E. Regional Differences

   1. None identified.

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Standard PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program

A. Introduction

1. Title: Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.
2. Number: PRC-010-0
3. Purpose: Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.
4. Applicability:
   4.1. Load-Serving Entity that operates a UVLS program
   4.2. Transmission Owner that owns a UVLS program
   4.3. Transmission Operator that operates a UVLS program
   4.4. Distribution Provider that owns or operates a UVLS program
5. Effective Date: April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).
   R1.1. This assessment shall include, but is not limited to:
      R1.1.1. Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.
      R1.1.2. Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.
      R1.1.3. A review of the voltage set points and timing.

R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).

C. Measures

M1. Each Transmission Owner’s and Distribution Provider’s UVLS program shall include the elements identified in Reliability Standard PRC-010-0 R1.

M2. Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0 R2.
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Assessments every five years or as required by System changes. Current assessment on request (30 calendar days.)

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: An assessment of the UVLS program did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided.

E. Regional Differences

1. None identified.

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A. Introduction
1. Title: Undervoltage Load Shedding System Maintenance and Testing
2. Number: PRC-011-0
3. Purpose: Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.
4. Applicability:
   4.1. Transmission Owner that owns a UVLS system
   4.2. Distribution Provider that owns a UVLS system
5. Effective Date: April 1, 2005

B. Requirements
R1. The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:
   R1.1. The UVLS system identification which shall include but is not limited to:
      R1.1.1. Relays.
      R1.1.2. Instrument transformers.
      R1.1.3. Communications systems, where appropriate.
      R1.1.4. Batteries.
   R1.2. Documentation of maintenance and testing intervals and their basis.
   R1.3. Summary of testing procedure.
   R1.4. Schedule for system testing.
   R1.5. Schedule for system maintenance.
   R1.6. Date last tested/maintained.
R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures
M1. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have documentation that its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0_R1.
M2. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program as specified in Reliability Standard PRC-011-0_R2.

D. Compliance
1. Compliance Monitoring Process
1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe
On request (30 calendar days).

1.3. Data Retention
None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was complete, but records indicate implementation was not on schedule.

2.2. Level 2: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

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A. Introduction

1. Title: Special Protection System Review Procedure

2. Number: PRC-012-0

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. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

   R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.

   R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.

   R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

   R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.

   R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.

   R1.6. Regional Reliability Organization definition of misoperation.

   R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.


   R1.9. Determination, as appropriate, of maintenance and testing requirements.

R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).
C. Measures

M1. The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use an SPS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility
   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe
   On request (within 30 calendar days.)

   1.3. Data Retention
   None specified.

   1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance

   2.1. Level 1: Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-0_R1.

   2.2. Level 2: Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-0_R1.

   2.3. Level 3: Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-0_R1.

   2.4. Level 4: Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

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A. Introduction

1. Title: Special Protection System Database.
2. Number: PRC-013-0
3. Purpose: To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:
   R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,
   R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and
   R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.

R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with an SPS installed, shall have an SPS database as defined in PRC-013-0_R1 of this Reliability Standard.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility
   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe
   On request (within 30 calendar days.)

   1.3. Data Retention
   None specified.

   1.4. Additional Compliance Information
   None.
2. Levels of Non-Compliance

2.1. **Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0_R1.

2.2. **Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-9_R1.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0_R1.

E. Regional Differences

1. None identified.

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A. Introduction

1. **Title:** Special Protection System Assessment
2. **Number:** PRC-014-0
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 Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.

R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

R3. The documentation of the Regional Reliability Organization’s SPS assessment shall include the following elements:
   R3.1 Identification of group conducting the assessment and the date the assessment was performed.
   R3.2 Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
   R3.3 Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.
   R3.4 Discussion of any coordination problems found between a SPS and other protection and control systems.
   R3.5 Provide corrective action plans for non-compliant SPSs.

C. Measures

M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.

M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

M3. The Regional Reliability Organization’s documentation of the SPS assessment shall include all elements as defined in Reliability Standard PRC-014-0 R3.
D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Compliance Monitor: NERC.
   1.2. Compliance Monitoring Period and Reset Timeframe
       On request (within 30 calendar days.)
   1.3. Data Retention
       None specified.
   1.4. Additional Compliance Information
       None.

2. Levels of Non-Compliance
   2.1. Level 1: The summary (or detailed) Regional SPS assessment is missing one of the items listed in Reliability Standard PRC-014-0_R3.
   2.2. Level 2: The summary (or detailed) Regional SPS assessment is missing two of the items listed in Reliability Standard PRC-014-0_3.
   2.3. Level 3: The summary (or detailed) Regional SPS assessment is missing three of the items listed in Reliability Standard PRC-014-0_R3.
   2.4. Level 4: The summary (or detailed) Regional SPS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. Title: Special Protection System Data and Documentation
2. Number: PRC-015-0
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: April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it maintains a list of and provides data for existing and proposed SPSs as defined in Reliability Standard PRC-013-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 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 Timeframe**
   On request (within 30 calendar days).

1.3. **Data Retention**
   None specified.

1.4. **Additional Compliance Information**
   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** SPS owners provided SPS data, but was incomplete according to the Regional Reliability Organization SPS database requirements.

   2.2. **Level 2:** SPS owners provided results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** No SPS data was provided in accordance with Regional Reliability Organization SPS database requirements for Standard PRC-012-0_R1, or the results of studies that show compliance of new or functionally modified SPSs with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

E. **Regional Differences**

   1. None identified.

**Version History**

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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: May 13, 2009

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.

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<td>May 13, 2009</td>
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A. Introduction

1. **Title:** Special Protection System Maintenance and Testing

2. **Number:** PRC-017-0

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:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:

   R1.1. SPS identification shall include but is not limited to:
       R1.1.1. Relays.
       R1.1.2. Instrument transformers.
       R1.1.3. Communications systems, where appropriate.
       R1.1.4. Batteries.

   R1.2. Documentation of maintenance and testing intervals and their basis.

   R1.3. Summary of testing procedure.

   R1.4. Schedule for system testing.

   R1.5. Schedule for system maintenance.

   R1.6. Date last tested/maintained.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. **Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. **Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. **Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. **Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

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</table>
A. Introduction

1. Title: Disturbance Monitoring Equipment Installation and Data Reporting
2. Number: PRC-018-1
3. Purpose: Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.
4. Applicability
   4.1. Transmission Owner.
   4.2. Generator Owner.
5. Effective Dates: Phased in over four years after BOT adoption:
   Requirements 1 and 2:
   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.
   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.
   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:
   – 100% compliant six months after BOT adoption for already installed DME.
   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:
   R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)
   R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region’s installation requirements (reliability standard PRC-002 Requirements 1.1, 2.1 and 3.1):
   R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).
   R3.2. Make and model of equipment.
R3.3. Installation location.
R3.4. Operational status.
R3.5. Date last tested.
R3.6. Monitored elements, such as transmission circuit, bus section, etc.
R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.
R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization’s requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization’s requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization’s DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization’s Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization’s DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame
One calendar year.

1.3. Data Retention
The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization’s installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization’s Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization’s installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization’s Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization’s installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.
2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization’s Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. **Level 4:** There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization’s installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization’s Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals.

E. **Regional Differences**

None identified.

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A. Introduction

1. Title: Under-Voltage Load Shedding Program Database
2. Number: PRC-020-1
3. Purpose: Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.

4. Applicability
   4.1. Regional Reliability Organization with entities that own or operate a UVLS program.

5. Effective Date: May 1, 2006

B. Requirements

R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
   R1.1. Owner and operator of the UVLS program.
   R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
   R1.3. Corresponding voltage set points and overall scheme clearing times.
   R1.4. Time delay from initiation to trip signal.
   R1.5. Breaker operating times.
   R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.

R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

C. Measures

M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.

M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       NERC
   1.2. Compliance Monitoring Period and Reset Time Frame
       One calendar year.
   1.3. Data Retention
The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS database annually.

2.2. Level 2: UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide information from its UVLS program database.

E. Regional Differences

None identified.

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<td>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</td>
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A. Introduction

1. Title: Under-Voltage Load Shedding Program Data
2. Number: PRC-021-1
3. Purpose: Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. Applicability

4.1. Transmission Owner that owns a UVLS program.

4.2. Distribution Provider that owns a UVLS program.

5. Effective Date: August 1, 2006

B. Requirements

R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:

R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
R1.2. Corresponding voltage set points and overall scheme clearing times.
R1.3. Time delay from initiation to trip signal.
R1.4. Breaker operating times.
R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.

R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

C. Measures

M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.

M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

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
Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

1.4. **Additional Compliance Information**

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

2.1. **Level 1**: Did not update its UVLS data annually.

2.2. **Level 2**: UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

2.3. **Level 3**: UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

2.4. **Level 4**: Did not provide any UVLS data.

E. **Regional Differences**

None identified.

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A. Introduction
1. Title: Under-Voltage Load Shedding Program Performance
2. Number: PRC-022-1
3. Purpose: Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. Applicability
   4.1. Transmission Operator that operates a UVLS program.
   4.2. Distribution Provider that operates a UVLS program.
   4.3. Load-Serving Entity that operates a UVLS program.
5. Effective Date: May 1, 2006

B. Requirements

R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:
   R1.1. A description of the event including initiating conditions.
   R1.2. A review of the UVLS set points and tripping times.
   R1.3. A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.
   R1.4. A summary of the findings.
   R1.5. For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.

R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.

C. Measures

M1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have documentation of its analysis of UVLS operations and Misoperations in accordance with Requirement 1.1 through 1.5.

M2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have evidence that it provided documentation of its analysis of UVLS program performance within 90 calendar days of a request by the Regional Reliability Organization.

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**

Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall retain documentation of its analyses of UVLS operations and Misoperations for two years. The Compliance Monitor shall retain any audit data for three years.

1.4. **Additional Compliance Information**

Transmission Operator, Load-Serving Entity, and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

2.1. **Level 1**: Not applicable.

2.2. **Level 2**: Documentation of the analysis of UVLS performance was provided but did not include one of the five requirements in R1.

2.3. **Level 3**: Documentation of the analysis of UVLS performance was provided but did not include two or more of the five requirements in R1.

2.4. **Level 4**: Documentation of the analysis of UVLS performance was not provided.

E. **Regional Differences**

None identified.

**Version History**

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<td>1. Removed comma after 2004 in “Development Steps Completed,” #1.</td>
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<td>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</td>
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<td>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</td>
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<td></td>
<td>4. Added or removed “periods” where appropriate.</td>
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<td>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</td>
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A. Introduction

1. Title: Transmission Relay Loadability
2. Number: PRC-023-1
3. Purpose: Protective relay settings shall not limit transmission loadability; not interfere with system operators’ ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. Applicability:
   4.1. Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:
      4.1.1 Transmission lines operated at 200 kV and above.
      4.1.2 Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.
      4.1.3 Transformers with low voltage terminals connected at 200 kV and above.
      4.1.4 Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.
   4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.
   4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.
   4.4. Planning Coordinators.

5. Effective Dates:

   5.1. Requirement 1, Requirement 2:
      5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — the beginning of the first calendar quarter following applicable regulatory approvals.
      5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.
      5.1.3 Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator’s critical facilities list determined pursuant to R3.1.

   5.2. Requirement 3: 18 months following applicable regulatory approvals.

---

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.
B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

R1.1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

R1.2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating\(^2\) of a circuit (expressed in amperes).

R1.3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

R1.3.1. An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

R1.3.2. An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

R1.4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

R1.5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

R1.6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

R1.7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

\(^2\) When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.
R1.8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

R1.9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

R1.10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:
- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

R1.11. For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:
- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100°C for the top oil or 140°C for the winding hot spot temperature.

R1.12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

R1.12.1. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

R1.12.2. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

R1.12.3. Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

R1.13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator.

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3 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.
with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3. The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3.1. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

R3.1.1. This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

R3.2. The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

M2. The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

M3. The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the appropriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Compliance Enforcement Authority

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.
The Compliance Monitor shall retain its compliance documentation for three years.

1.4. **Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.
### 2. Violation Severity Levels:

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<th>Moderate</th>
<th>High</th>
<th>Severe</th>
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<td>R1</td>
<td>Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.</td>
<td>Relay settings do not comply with any of the sub requirements R1.1 through R1.13 OR Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.</td>
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<td>Criteria described in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.</td>
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<td>R3</td>
<td>Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.</td>
<td>Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.</td>
<td>Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System. OR Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System, OR Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more than 60 days after the list was established or updated.</td>
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**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.


**Version History**

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<td>Approved by Board of Trustees</td>
<td>New</td>
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<td>March 19, 2008</td>
<td>Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”</td>
<td>Errata</td>
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<tr>
<td>1</td>
<td>March 18, 2010</td>
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Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   1.1. Phase distance.
   1.2. Out-of-step tripping.
   1.3. Switch-on-to-fault.
   1.4. Overcurrent relays.
   1.5. Communications aided protection schemes including but not limited to:
       1.5.1 Permissive overreach transfer trip (POTT).
       1.5.2 Permissive under-reach transfer trip (PUTT).
       1.5.3 Directional comparison blocking (DCB).
       1.5.4 Directional comparison unblocking (DCUB).

2. This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

3. The following protection systems are excluded from requirements of this standard:
   3.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
       ● Overcurrent elements that are only enabled during loss of potential conditions.
       ● Elements that are only enabled during a loss of communications.
   3.2. Protection systems intended for the detection of ground fault conditions.
   3.3. Protection systems intended for protection during stable power swings.
   3.4. Generator protection relays that are susceptible to load.
   3.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
   3.6. Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
   3.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
   3.8. Relay elements associated with DC lines.
   3.9. Relay elements associated with DC converter transformers.
A. Introduction

1. Title: Certification of Protective Relay Applications and Settings
2. Number: PRC-STD-001-1
3. Purpose: Regional Reliability Standard to certify all protective relay applications for the Bulk Power Transmission Paths\(^1\) of the Western Interconnection.

4. Applicability

4.1. This criterion applies to each Transmission Operator or Transmission Owner (as specified in Section B) of a transmission path in the Attachment A – WECC Table 2 (Source: Participants Subject to Criterion)

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1.

Each Transmission Operator or Transmission Owner identified in Section 4.1 must submit documentation that an officer of the organization certifies that:

a. All protective relay applications are appropriate for the Bulk Power Transmission Paths ("BPTP") identified in Attachment A – Table 2 of this Standard pursuant to applicable WECC Standards and NERC Standards;

b. The BPTP protective relay settings and logic are appropriate pursuant to applicable WECC Standards and NERC Standards;

c. Since the last certification or for the last three years all network changes in the path, at the terminals of the path, or in nearby facilities that affect operation of the path have been considered in the protective relay application and settings;

d. All relay operations since the last certification or during the last three-year period have been analyzed for correctness and appropriate corrective action taken pursuant to applicable WECC Standards and NERC Standards;

e. Up-to-date relay information has been provided to the on-shift operating personnel and the appropriate Reliability Coordinator.

Note: If a path operator cannot submit certification on behalf of the multiple owners of a path for Protective Relay Application and Settings because the authority for certification resides with one or more path owners, then the path owner(s) shall submit the certification. The path operator

\(^1\) WECC Table 2
shall notify the path owner(s) and WECC in writing that the path owner(s) is (are) to submit the certification. (Source: WECC Criterion)

C. Measures

WM1. A Transmission Operator or Transmission Owner identified in Section A.4.1 must accurately complete the Protective Relay Application and Settings Certification form. (Source: Compliance Standard)

D. Compliance

1. Compliance Monitoring Process

   1.1 Compliance Monitoring Responsibility
       Western Electricity Coordinating Council (WECC)

   1.2 Compliance Monitoring Period
       Yearly
       On or before September 15 of each year (or such other date as specified in Form A.7), a Transmission Operator or Transmission Owner identified in Section A.4.1 shall submit to the WECC office the completed Protective Relay Application and Settings Certification form as specified in Form A.7 (available on the WECC web site). (Source: Data Reporting Requirement)

   1.3 Data Retention
       Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

   1.4. Additional Compliance Information
       For purposes of applying the sanctions specified in Section II for violations of this criterion, the “Sanction Measure” is Normal Path Rating and the “Specified Period” is the most recent 12 month period ending August 31. (Source: Sanctions)

2. Levels of Non-Compliance

   Sanction Measure: Normal Path Rating

   2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:
       2.1.1 The reporting Transmission Operator or Transmission Owner accurately certified to completing items (a) and (b) and all but one of items (c)-(e) listed above in Section B.

   2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:
       2.2.1 The reporting Transmission Operator or Transmission Owner accurately certified to completing items (a) and (b) and all but two of items (c)-(e) listed above in Section B.
2.3. **Level 3:** There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 The reporting Transmission Operator or Transmission Owner accurately certified to completing of items (a) and (b) and to all but three of items (c)-(e) listed above in Section B.

2.4. **Level 4:** There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 The reporting Transmission Operator or Transmission Owner did not certify to completion of either item (a) or (b) or did not certify to the completion of any four of items (c)-(e) listed above in Section B.

E. **Regional Differences**

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**Version History** – Shows Approval History and Summary of Changes in the Action Field
Sanction Table

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

| Level of Non-compliance | Number of Occurrences at a Given Level within Specified Period | | |
|-------------------------|---------------------------------------------------------------|---|---|---|
|                         | 1                                                                 | 2 | 3 | 4 or more |
| Level 1                 | Letter (A)                                                      | Letter (B) | Higher of $1,000 or $1 per MW of Sanction Measure | Higher of $2,000 or $2 per MW of Sanction Measure |
| Level 2                 | Letter (B)                                                      | Higher of $1,000 or $1 per MW of Sanction Measure | Higher of $2,000 or $2 per MW of Sanction Measure | Higher of $4,000 or $4 per MW of Sanction Measure |
| Level 3                 | Higher of $1,000 or $1 per MW of Sanction Measure               | Higher of $2,000 or $2 per MW of Sanction Measure | Higher of $4,000 or $4 per MW of Sanction Measure | Higher of $6,000 or $6 per MW of Sanction Measure |
| Level 4                 | Higher of $2,000 or $2 per MW of Sanction Measure               | Higher of $4,000 or $4 per MW of Sanction Measure | Higher of $6,000 or $6 per MW of Sanction Measure | Higher of $10,000 or $10 per MW of Sanction Measure |

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D.1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be

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2 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.
### ATTACHMENT A

**Table 2**

**Existing WECC Transfer Paths (BPTP)**

(Revised February 1, 2006)

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<td>BCTC/AESO</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>3</td>
<td>BCTC/BPA</td>
</tr>
<tr>
<td>3. West of Cascades – North</td>
<td>4</td>
<td>BPA</td>
</tr>
<tr>
<td>4. West of Cascades – South</td>
<td>5</td>
<td>BPA</td>
</tr>
<tr>
<td>5. West of Hatwai</td>
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<td>AVA/BPA</td>
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<td>6. Montana to Northwest</td>
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<td>NWMT</td>
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<tr>
<td>7. Idaho to Northwest</td>
<td>14</td>
<td>IPC</td>
</tr>
<tr>
<td>8. South of Los Banos or Midway - Los Banos</td>
<td>15</td>
<td>CISO</td>
</tr>
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<td>9. Idaho – Sierra</td>
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<td>SPP</td>
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<td>10. Borah West</td>
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<td>CISO</td>
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<tr>
<td>17. Intmtntn. Power Project DC Line</td>
<td>27</td>
<td>LADWP</td>
</tr>
<tr>
<td>18. TOT 1A</td>
<td>30</td>
<td>WAPA</td>
</tr>
<tr>
<td>19. TOT 2A</td>
<td>31</td>
<td>WAPA</td>
</tr>
<tr>
<td>20. Pavant – Gonder 230 kV</td>
<td>32</td>
<td>SPP/LADWP</td>
</tr>
<tr>
<td>Intermountain – Gonder 230 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>21. TOT 2B</td>
<td>34</td>
<td>PAC</td>
</tr>
<tr>
<td>22. TOT 2C</td>
<td>35</td>
<td>NEVP</td>
</tr>
<tr>
<td>23. TOT 3</td>
<td>36</td>
<td>WAPA</td>
</tr>
<tr>
<td>24. TOT 5</td>
<td>39</td>
<td>WAPA</td>
</tr>
<tr>
<td>25. SDGE – CFE</td>
<td>45</td>
<td>CISO/CFE</td>
</tr>
<tr>
<td>26. West of Colorado River (WOR)</td>
<td>46</td>
<td>CISO</td>
</tr>
<tr>
<td>27. Southern New Mexico (NM1)</td>
<td>47</td>
<td>EPE</td>
</tr>
<tr>
<td>28. Northern New Mexico (NM2)</td>
<td>48</td>
<td>PNM</td>
</tr>
<tr>
<td>29. East of the Colorado River (EOR)</td>
<td>49</td>
<td>APS</td>
</tr>
<tr>
<td>30. Cholla – Pinnacle Peak</td>
<td>50</td>
<td>APS</td>
</tr>
<tr>
<td>31. Southern Navajo</td>
<td>51</td>
<td>APS</td>
</tr>
<tr>
<td>32. Brownlee East</td>
<td>55</td>
<td>IPC</td>
</tr>
<tr>
<td>33. Lugo – Victorville 500 kV</td>
<td>61</td>
<td>CISO/LDWP</td>
</tr>
<tr>
<td>34. Pacific DC Intertie</td>
<td>65</td>
<td>BPA/LADWP</td>
</tr>
<tr>
<td>35. COI</td>
<td>66</td>
<td>BPA/CISO</td>
</tr>
<tr>
<td>36. North of John Day cutplane</td>
<td>73</td>
<td>BPA</td>
</tr>
<tr>
<td>37. Alturas</td>
<td>76</td>
<td>SPP</td>
</tr>
<tr>
<td>38. Montana Southeast</td>
<td>80</td>
<td>NWMT</td>
</tr>
<tr>
<td>39. SCIT**</td>
<td></td>
<td>CISO</td>
</tr>
<tr>
<td>40. COI/PDCI – North of John Day cutplane**</td>
<td></td>
<td>BPA</td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in the Standard and as set out below:

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**Normal Path Rating** is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

**WECC Table 2** means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A of this Standard.

EXCUSE OF PERFORMANCE

A. **Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

B. **Specific Excuses**

1. **Governmental Order**

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).
2. **Order of Reliability Coordinator**

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

   Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

   a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability
Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Standard. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

5. Participation in Field Testing

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-
compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
A. Introduction

1. Title: Protective Relay and Remedial Action Scheme Misoperation
2. Number: PRC-STD-003-1
3. Purpose: Regional Reliability Standard to ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-STD-003-1 is a Regional Reliability Standard that meets Requirement 1 of the NERC Standard PRC-003-1.

4. Applicability

4.1. This criterion applies to each Transmission Operator or Transmission Owner (as specified in Section B) of a transmission path in the Attachment A – WECC Table 2 and owners of Remedial Action Schemes listed in Table 3, Attachment B, Existing WECC Remedial Action Schemes (Source: Participants Subject to Criterion).

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1.

Owners of protective relays and Remedial Action Schemes (RAS) applied to path elements of selected WECC major transmission path facilities (listed in Attachment A – Table 2) and RAS (listed in Attachment B – Table 3) must take the following action for each known or probable relay misoperation:

a. If functionally equivalent protective relaying or RAS remains in service to ensure bulk transmission system reliability; the relay or RAS that misoperated is to be removed from service for repair or modification within 22 hours of the relay or RAS misoperation. The relay or RAS shall be replaced, repaired, or modified such that the incorrect operation will not be repeated.

b. If functionally equivalent protective relaying or RAS does not remain in service that will ensure bulk transmission system reliability, and the relay or RAS that misoperated cannot be repaired and placed back in service within 22 hours, the associated transmission path facility must be removed from service. The remaining path facilities, if any, must be de-rated to a reliable operating level.

c. If the relay or RAS misoperates and there is some protection but not entirely functionally equivalent, the relay or RAS must be repaired or removed from service within 22 hours. The associated transmission may remain in service; however, system operation must fully comply with WECC and NERC operating standards. This may require an adjustment of operating levels.
d. Protective relays or RAS removed from service must be repaired or replaced with functionally equivalent protective relays or RAS within 20 Business Days of removal, or the system shall be operated at levels that meet WECC Standards and NERC Standards or the associated transmission path elements shall be removed from service.

It is not intended that the above requirements apply to system protection and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with WECC and NERC standards, and the protective relaying or RAS operation is later found to be incorrect. In such cases, upon determination of the incorrect operation, the requirements of (a) through (d) above will become applicable at the time the incorrect operation is identified. (Source: WECC Criterion)

C. Measures

WM1. A Transmission Operator and/or owners of Remedial Action Schemes identified in Section A.4.1 shall submit to the WECC office the completed Protective Relay and Remedial Action Scheme Misoperation Reporting Form. (Source: Data Reporting Requirement)

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Western Electricity Coordinating Council (WECC)

1.2 Compliance Monitoring Period

At Occurrence

With respect to requirements (a) through (c) of Section B, by no later than 5 Business Days following the occurrence of a known or probable relay misoperation and/or a known or probable RAS misoperation, a Responsible Entity identified in Section A.4.1 shall submit to the WECC office the completed Protective Relay and Remedial Action Scheme Misoperation Reporting Form(s) as specified in Form A.9 (available on the WECC web site).

With respect to requirement (d) of Section B, by no later than 30 Business Days following the occurrence of a known or probable relay misoperation and/or a known or probable RAS misoperation, a Responsible Entity identified in Section A.4.1 shall submit to the WECC office the completed Protective Relay and Remedial Action Scheme Misoperation Reporting Form(s) as specified in Form A.9 (available on the WECC web site). (Source: Data Reporting Requirement)

1.3 Data Retention

Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

1.4. Additional Compliance Information
2. Levels of Non-Compliance

Sanction Measure: Normal Path Rating

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 For requirements (a) through (c) of Section B, the relay or RAS that misoperated was removed from service, repaired, or other compliance measures implemented as described in requirements (a) through (c) in > 22 hours but ≤ 24 hours.

2.1.2 For requirement (d) of Section B, repairs or replacement > 20 business days ≤ 25 business days and system operation not adjusted to comply with applicable WECC Standards and NERC Standards in the case where there is not redundant relay protection or RAS.

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 For requirements (a) through (c) of Section B, the relay or RAS that misoperated was removed from service, repaired, or other compliance measures implemented as described in requirements (a) through (c) in > 24 hours but ≤ 28 hours.

2.2.2 For requirement (d) of Section B, repairs or replacement > 25 business days ≤ 28 business days and system operation not adjusted to comply with applicable WECC Standards and NERC Standards in the case where there is not redundant relay protection or RAS.

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 For requirements (a) through (c) of Section B, the relay or RAS that misoperated was removed from service, repaired, or other compliance measures implemented as described in requirements (a) through (c) in > 28 hours but ≤ 32 hours.

2.3.2 For requirement (d) of Section B, repairs or replacement > 28 business days ≤ 30 business days and system operation not adjusted to comply with applicable WECC Standards and NERC Standards in the case where there is not redundant relay protection or RAS.

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 For requirements (a) through (c) of Section B, the relay or RAS that misoperated was removed from service, repaired, or other compliance measures implemented as described in requirements (a) through (c) in ≤ 32 hours.

2.4.2 For requirement (d) of Section B, repairs or replacement ≤ 30 business days and system operation not adjusted to comply with applicable
E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
</table>

References:
NERC Standard PRC-016-0 R2 requires corrective action but there is no required timeframe to remove element from service or to derate the path if required.

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1 References are provided for informational purposes only and are not a component of WECC Reliability Standards.
**Sanction Table**

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
<thead>
<tr>
<th>Level of Non-compliance</th>
<th>Number of Occurrences at a Given Level within Specified Period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Level 1</td>
<td>Letter (A)</td>
</tr>
<tr>
<td>Level 2</td>
<td>Letter (B)</td>
</tr>
<tr>
<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
</tbody>
</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D.1.4 for each criterion.

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2 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of non-compliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.
### ATTACHMENT A

**Table 2**

*Existing WECC Transfer Paths (BPTP)*

*(Revised February 1, 2006)*

<table>
<thead>
<tr>
<th>PATH NAME*</th>
<th>Path Number</th>
<th>Operating Agent</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>1</td>
<td>BCTC/AESO</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>3</td>
<td>BCTC/BPA</td>
</tr>
<tr>
<td>3. West of Cascades – North</td>
<td>4</td>
<td>BPA</td>
</tr>
<tr>
<td>4. West of Cascades – South</td>
<td>5</td>
<td>BPA</td>
</tr>
<tr>
<td>5. West of Hatwai</td>
<td>6</td>
<td>AVA/BPA</td>
</tr>
<tr>
<td>6. Montana to Northwest</td>
<td>8</td>
<td>NWMT</td>
</tr>
<tr>
<td>7. Idaho to Northwest</td>
<td>14</td>
<td>IPC</td>
</tr>
<tr>
<td>8. South of Los Banos or Midway- Los Banos</td>
<td>15</td>
<td>CISO</td>
</tr>
<tr>
<td>9. Idaho – Sierra</td>
<td>16</td>
<td>SPP</td>
</tr>
<tr>
<td>10. Borah West</td>
<td>17</td>
<td>IPC</td>
</tr>
<tr>
<td>11. Idaho – Montana</td>
<td>18</td>
<td>NWMT</td>
</tr>
<tr>
<td>12. Bridger West</td>
<td>19</td>
<td>PAC</td>
</tr>
<tr>
<td>13. Path C</td>
<td>20</td>
<td>PAC</td>
</tr>
<tr>
<td>14. Southwest of Four Corners</td>
<td>22</td>
<td>APS</td>
</tr>
<tr>
<td>15. PG&amp;E – SPP</td>
<td>24</td>
<td>CISO</td>
</tr>
<tr>
<td>16. Northern – Southern California</td>
<td>26</td>
<td>CISO</td>
</tr>
<tr>
<td>17. Intmttn. Power Project DC Line</td>
<td>27</td>
<td>LADWP</td>
</tr>
<tr>
<td>18. TOT 1A</td>
<td>30</td>
<td>WAPA</td>
</tr>
<tr>
<td>19. TOT 2A</td>
<td>31</td>
<td>WAPA</td>
</tr>
<tr>
<td>20. Pavant – Gonder 230 kV Intermountain – Gonder 230 kV</td>
<td>32</td>
<td>SPP/LADWP</td>
</tr>
<tr>
<td>21. TOT 2B</td>
<td>34</td>
<td>PAC</td>
</tr>
<tr>
<td>22. TOT 2C</td>
<td>35</td>
<td>NEVP</td>
</tr>
<tr>
<td>23. TOT 3</td>
<td>36</td>
<td>WAPA</td>
</tr>
<tr>
<td>24. TOT 5</td>
<td>39</td>
<td>WAPA</td>
</tr>
<tr>
<td>25. SDGE – CFE</td>
<td>45</td>
<td>CISO/CFE</td>
</tr>
<tr>
<td>26. West of Colorado River (WOR)</td>
<td>46</td>
<td>CISO</td>
</tr>
<tr>
<td>27. Southern New Mexico (NM1)</td>
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<td>EPE</td>
</tr>
<tr>
<td>28. Northern New Mexico (NM2)</td>
<td>48</td>
<td>PNM</td>
</tr>
<tr>
<td>29. East of the Colorado River (EOR)</td>
<td>49</td>
<td>APS</td>
</tr>
<tr>
<td>30. Cholla – Pinnacle Peak</td>
<td>50</td>
<td>APS</td>
</tr>
<tr>
<td>31. Southern Navajo</td>
<td>51</td>
<td>APS</td>
</tr>
<tr>
<td>32. Brownlee East</td>
<td>55</td>
<td>IPC</td>
</tr>
<tr>
<td>33. Lugo – Victorville 500 kV</td>
<td>61</td>
<td>CISO/LDWP</td>
</tr>
<tr>
<td>34. Pacific DC Intertie</td>
<td>65</td>
<td>BPA/LADWP</td>
</tr>
<tr>
<td>35. COI</td>
<td>66</td>
<td>BPA/CISO</td>
</tr>
<tr>
<td>36. North of John Day cutplane</td>
<td>73</td>
<td>BPA</td>
</tr>
<tr>
<td>37. Alturas</td>
<td>76</td>
<td>SPP</td>
</tr>
<tr>
<td>38. Montana Southeast</td>
<td>80</td>
<td>NWMT</td>
</tr>
<tr>
<td>39. SCIT**</td>
<td></td>
<td>CISO</td>
</tr>
<tr>
<td>40. COI/PDCI – North of John Day cutplane**</td>
<td></td>
<td>BPA</td>
</tr>
</tbody>
</table>

- For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

**The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
## ATTACHMENT B

### Table 3

**Existing WECC Remedial Action Schemes**  
(Revised March 1, 2006)

<table>
<thead>
<tr>
<th>Path Name*</th>
<th>Path Number</th>
<th>RAS</th>
<th>Involved Parties</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>Path 1</td>
<td>Remedial actions are required to achieve the rated transfer capability. Most involve tripping tie lines for outages in the BCTC system. East to West: For high transfers, generation tripping is required north of the SOK cutplane in Alberta.</td>
<td>BCTC/AESO</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>Path 3</td>
<td>Generator and reactive tripping in the BCTC system to protect against the impact caused by various contingencies during transfers between British Columbia and the Northwest.</td>
<td>BCTC/BPA</td>
</tr>
<tr>
<td>3. West of Hatwai</td>
<td>Path 6</td>
<td>Generator dropping (Libby, Noxon, Lancaster, Dworshak); Reactor tripping (Garrison); Tripping of Miles City DC link.</td>
<td>AVA/BPA</td>
</tr>
<tr>
<td>4. Montana to Northwest</td>
<td>Path 8</td>
<td>Tripping Colstrip by ATR (NWMT); Switching shunt reactors at Garrison 500 kV; Tripping the back-to-back DC tie at Miles City; Tripping Libby, and Noxon generation by WM-RAS (BPA).</td>
<td>NWMT/BPA</td>
</tr>
<tr>
<td>5. Idaho to Northwest</td>
<td>Path 14</td>
<td>Generator Runback at Hells Canyon; Jim Bridger tripping for loss of Midpoint – Summer Lake 500 kV line.</td>
<td>IPC</td>
</tr>
<tr>
<td>6. Midway-Los Banos</td>
<td>Path 15</td>
<td>CDWR and PG&amp;E pump load dropping north of Path 15. PG&amp;E service area load dropping north of Path 15. PG&amp;E service area generation dropping south of Path 15.</td>
<td>CISO</td>
</tr>
<tr>
<td>7. Idaho Sierra</td>
<td>Path 16</td>
<td>Automatic load shedding is required when the Alturas line is open for loss of the Midpoint-Humbolt 345 kV line during high Sierra system imports.</td>
<td>SPP</td>
</tr>
<tr>
<td>8. Bridger West</td>
<td>Path 19</td>
<td>Jim Bridger tripping for delayed clearing and multi-line faults; Addition of shunt capacitors at Jim Bridger, Kinport and Goshen and series capacitor bypassing at Burns.</td>
<td>IPC</td>
</tr>
<tr>
<td>9. IPP DC Line</td>
<td>Path 27</td>
<td>IPP Contingency Arming System trips one or two IPP generating units.</td>
<td>LDWP</td>
</tr>
<tr>
<td>10. TOT1A</td>
<td>Path 30</td>
<td>Bonanza and Flaming Gorge generation is tripped for loss of the Bonanza-Mona 345 kV line to achieve rating on TOT1A.</td>
<td>WAPA</td>
</tr>
<tr>
<td></td>
<td>Path</td>
<td>Description</td>
<td>Responsible Party</td>
</tr>
<tr>
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<td>-----------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>11.</td>
<td>TOT2A</td>
<td>Path 31 For the Montrose-Hesperus 345 kV line outage with Nucla generation above 60 MW, the parallel Montrose-Nucla 115 kV line is automatically transfer tripped.</td>
<td>WAPA</td>
</tr>
<tr>
<td>12.</td>
<td>TOT2B</td>
<td>Path 34 Trip Huntington generation for loss of the Huntington-Pinto + Four Corners lines when parallel lines are heavily loaded.</td>
<td>PAC</td>
</tr>
<tr>
<td>13.</td>
<td>TOT5</td>
<td>Path 39 For an outage of the Hayden-Gore Pass 230 kV line, the lower voltage parallel path is tripped.</td>
<td>WAPA</td>
</tr>
<tr>
<td>14.</td>
<td>SDGE RAS</td>
<td>Path 44 RAS used to meet reactive margin criteria for loss of both San Onofre units.</td>
<td>SDGE</td>
</tr>
<tr>
<td>15.</td>
<td>SDGE – CFE</td>
<td>Path 45 The purpose of the RAS is to automatically cross-trip (transfer trip) the Miguel – Tijuana 230kV following the outage of Imperial Valley – Miguel 500kV line.</td>
<td>SDGE/CFE</td>
</tr>
<tr>
<td>16.</td>
<td>Southern New Mexico</td>
<td>Path 47 For double contingencies on the 345 kV lines defined in the path, WECC Operating Procedure EPE-1 is implemented.</td>
<td>EPE</td>
</tr>
<tr>
<td>17.</td>
<td>Pacific DC Intertie</td>
<td>Path 65 Northwest generator tripping; Series capacitor fast insertion; mechanically switched shunt capacitors</td>
<td>BPA/LDWP</td>
</tr>
<tr>
<td>18.</td>
<td>California – Oregon Intertie</td>
<td>Path 66 Northwest generator tripping; Chief Jo Brake insertion; Fort Rock Series Capacitor insertion; Northern California generator and pump load tripping; N. California series capacitor bypassing, shunt reactor or capacitor insertion; Initiation of NE/SE Separation Scheme at Four Corners.</td>
<td>BPA/CISO/APS</td>
</tr>
<tr>
<td>19.</td>
<td>Meridian 500/230 kV Transformers**</td>
<td>Following the loss of the Meridian 500/230kV transformers, RAS is used to comply with WECC Standards under high load conditions.</td>
<td>PAC</td>
</tr>
<tr>
<td>20.</td>
<td>Northern-Southern California</td>
<td>Path 26 Remedial action required to achieve the rated transfer capability. Midway area generation tripped for loss of any two of three Midway-Vincent 500 kV lines.</td>
<td>CISO</td>
</tr>
<tr>
<td>21.</td>
<td>PNM Import Contingency Load Shedding Scheme (ICLSS)</td>
<td>Path 48 ICLSS is a centralized load shedding scheme for low probability events such as simultaneous outage of the Four Corners-West Mesa (FW) 345 kV and San Juan-B-A (WW) 345 kV lines, as well as any unplanned disturbance affecting voltage in the Northern New Mexico transmission system.</td>
<td>PNM</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>---</td>
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<td></td>
</tr>
<tr>
<td>22.</td>
<td><strong>Valley Direct Load Trip (DLT)</strong></td>
<td>RAS is required for the loss of the Serrano-Valley 500 kV line. About 200 MW of Valley load is tripped.</td>
<td>SCE</td>
</tr>
<tr>
<td>23.</td>
<td><strong>South of Lugo N-2 RAS</strong></td>
<td>RAS is required for the simultaneous double line outage of any combination of the Lugo-Mira Loma 1 (when looped), 2, and 3 500 kV lines and the Lugo-Serrano (when de-looped) 500 kV line.</td>
<td>SCE</td>
</tr>
<tr>
<td>24.</td>
<td><strong>Lower Snake RAS</strong></td>
<td>The RAS is required to protect for the double line outage of the Lower Monumental-Little Goose 500-kV lines. Generation is dropped at Little Goose and Lower Granite Powerhouses as well as key the WM RAS. An outage of the Little Goose – Lower Granite 500 kV lines will drop generation at Lower Granite Powerhouse and key the Western Montana RAS.</td>
<td>BPA</td>
</tr>
<tr>
<td>25.</td>
<td><strong>Palo Verde – COI Mitigation Scheme</strong></td>
<td>Path 66 Required to provide for safe operation of the COI for the loss of two units at Palo Verde Nuclear Generating Station (PVNGS). The RAS protects the PVNGS and Palo Verde Transmission System (PVTS) for faults at Palo Verde and subsequent outage of the Palo Verde – Westwing 500 kV lines.</td>
<td>SRP</td>
</tr>
<tr>
<td>26.</td>
<td><strong>Palo Verde/Hassayampa RAS</strong></td>
<td>Provides protection to the PVNGS and the PVTS for faults at Palo Verde and subsequent double line outage of the Palo Verde to Westwing 500 kV lines.***</td>
<td>SRP</td>
</tr>
<tr>
<td>27.</td>
<td><strong>Sierra Pacific – PacifiCorp RAS</strong></td>
<td>Path 76 Needed for loss of the 230 kV Malin-Hilltop line when heavily loaded unless automatic reclose is successful. The scheme closes the Hilltop 345 kV line reactor if pre-outage northbound flow is greater than 150 MW. For pre-outage southbound flow greater than 235 MW the Hilltop 345 kV line trips and the Hilltop 345 kV line reactors closes.</td>
<td>SPPC</td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The Meridian 500/230 kV transformers are not included in the Path Rating Catalog. The RAS associated with the Meridian transformers is included in Table 3 because the failure of the RAS may result in cascading.

*** The Palo Verde/Hassayampa RAS is designed to prevent cascading problems throughout the WECC region. This scheme is not Path related and is not used to protect any specific WECC Path.

## DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in this Standard and as set out below:
**Business Day** means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**Normal Path Rating** is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

**WECC Table 2** means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Reliability Agreement.

### EXCUSE OF PERFORMANCE

**A. Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

**B. Specific Excuses**

1. **Governmental Order**

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. **Order of Reliability Coordinator**

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability
Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. Protection of Facilities

Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. Extraordinary Contingency

a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Reliability Agreement. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy
or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

5. **Participation in Field Testing**

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
A. Introduction

1. Title: Transmission Maintenance
2. Number: PRC-STD-005-1
3. Purpose: Regional Reliability Standard to ensure the Transmission Operator or Owner of a transmission path identified in Attachment A perform maintenance and inspection on identified paths as described by its transmission maintenance plan.

4. Applicability

4.1. This Standard is applicable to Transmission Owners or Operators that maintain the transmission paths in Attachment A – WECC Table 2 and is applicable only to those facilities associated with each of the paths identified. (Source: Participants Subject to Criterion)

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1.

All bulk power transmission elements (i.e. lines, stations and rights of way) included as part of the transmission facilities (or required to maintain transfer capability) impacting each of the transmission paths listed in Attachment A – WECC Table 2 shall be inspected and maintained in accordance with this criterion, taking into consideration diverse environmental and climatic conditions, terrain, equipment, maintenance philosophies, and design practices.

a. General

This Transmission Maintenance Standard requires each Responsible Entity identified in Section A.4.1 to develop and implement a Transmission Maintenance and Inspection Plan (TMIP) detailing the Responsible Entity’s inspection and maintenance activities applicable to the transmission facilities comprising each of the transmission paths identified in Attachment A – Table 2.

b. Standard Requirements

(i) TMIP

To comply with this Standard, each Responsible Entity identified in Section A4.1 must develop and implement a TMIP.

- Because maintenance and inspection practices vary, it is the intent of this Transmission Maintenance Standard to allow flexibility in inspection and maintenance practices while still requiring a description of certain specific inspection and maintenance practices.
(a) TMIP Contents

The TMIP may be performance-based, time-based, conditional-based, or a combination of all three as may be appropriate. The TMIP shall:

- Identify the facilities for which it is covering by listing the names of each transmission path and the quantities of each equipment component, such as; circuit breaker, relay scheme, transmission line;
- Include the scheduled interval (e.g., every two years) for any time-based maintenance activities and a description of conditions that will initiate any condition or performance-based activities;
- Describe the maintenance, testing and inspection methods for each activity or component listed under Transmission Line Maintenance and Station Maintenance;
- Provide any checklists or forms, or reports used for maintenance activities;
- Provide criteria to be used to assess the condition of a transmission facility or component;
- Specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the transmission facilities;
- Include specific details regarding Transmission Line and Station Maintenance practices as per subsections (1) and (2) below.

(1) Transmission Line Maintenance Details

The TMIP shall, at a minimum, describe the Responsible Entity’s practices for the following transmission line maintenance activities:

- Patrol/Inspection;
- Contamination Control (Insulator Washing)

(2) Station Maintenance Details

The TMIP shall describe the Responsible Entity’s maintenance practices for the following station equipment:

- Circuit Breakers
- Power Transformers (including phase-shifting transformers)
- Regulators
- Protective Relay Systems and associated Communication Equipment
• RAS Systems and associated Communication Equipment
• Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)

(ii) Maintenance Record Keeping

M1.
Each Responsible Entity identified in Section A.4.1 must retain all pertinent maintenance and inspection records that support the TMIP according to the following guidelines:

• The Responsible Entity shall maintain records of all maintenance and inspection activities for at least five years.
• Each Responsible Entity’s maintenance and inspection records shall identify, at a minimum:
  o The person(s) responsible for performing the work or inspection;
  o The date(s) the work or inspection was performed;
  o The transmission facility on which the work was performed, and
  o A description of the inspection or maintenance performed.

The Transmission Owner or Operator shall maintain (and make available on request) records for maintenance or inspection pertaining to the items listed in subsections (a) and (b) below.

(a) Transmission Line Maintenance Records
• Patrol/Inspection
• Contamination Control (Insulator Washing)

(b) Station Maintenance Records
• Circuit Breakers
• Power Transformers
• Regulators
• Protective Relay Systems and associated Communication Equipment
• RAS Systems and associated Communication Equipment
• Reactive Devices

c. Compliance Measures
This section defines the items that will be reviewed by WECC Staff to monitor and measure each Responsible Entity’s compliance with this Standard, and the compliance levels that will be assessed in the review process.

(i) TMIP Certification

Each Responsible Entity identified in Section A.4.1 shall annually certify to WECC Staff that it has developed, documented, and implemented a TMIP.

(ii) WECC Staff Review

WECC Staff will assess performance in the three broad areas described in Paragraph 8 of the Certification Form. These areas are:

1. Development and documentation of the TMIP;
2. Performing maintenance in accordance with the TMIP;
3. Maintaining maintenance records as required by this Standard.

(iii) Review Triggers

The WECC Staff will conduct a review of the Responsible Entity’s TMIP, maintenance and inspection practices and maintenance records when triggered as described below.

(a) Disturbance Report. If a WECC Disturbance Report identifies that transmission maintenance and inspection activities were a substantial contributing factor in the disturbance, WECC Staff may request a review of the Responsible Entity.

(b) Recommendation by CMWG team. If in its tri-annual review, the CMWG review team notes areas in transmission availability or maintenance that warrant further review, they may recommend a review by the WECC Staff.

(c) Incomplete Annual Certification. If the Responsible Entity identified in Section A.4.1 fails to certify one or more categories of paragraph 8 of the Certification Plan, WECC Staff may request a review of the Responsible Entity.

(d) Random Audit. The WECC Staff shall randomly select two or three Responsible Entities each year for review. When a review is requested, the Responsible Entity shall make its TMIP and all maintenance records for the facilities that are part of RMS available to the WECC Staff for review within 30 calendar days from the request date.

C. Measures

WM1.
Each Responsible Entity identified in Section A.4.1 shall develop, document and implement a TMIP, perform maintenance in accordance with that TMIP, and maintain maintenance records as required by this Transmission Maintenance Standard. (Source: Compliance Standard)

Full compliance:

1. The Responsible Entity identified in Section A.4.1 has developed and documented a transmission maintenance, testing and inspection plan that meets the requirements of the Transmission Maintenance Standard.

2. The Responsible Entity identified in Section A.4.1 is performing maintenance, testing and inspections in accordance with its TMIP.

3. The Responsible Entity identified in Section A.4.1 is maintaining maintenance and inspection records as required by the Transmission Maintenance Standard.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility
Western Electricity Coordinating Council (WECC)

1.2 Compliance Monitoring Period
At Occurrence and Yearly

Each Responsible Entity identified in Section A.4.1 shall certify to the WECC Staff on or before January 15 of each year, that it has implemented a TMIP in compliance with this Transmission Maintenance Standard by submitting a completed Transmission Maintenance Certification Form (Form A.12).

If a review is triggered according to Section B.c (iii), a Responsible Entity identified in Section A.4.1 shall make its TMIP and maintenance records for those facilities available to the WECC Staff within 30 calendar days from the date requested. The WECC Staff may have to visit several maintenance headquarters or offices to review the maintenance records.

Each Responsible Entity identified in Section A.4.1 shall submit the completed form(s) by e-mail to the WECC Staff at the address specified in the form. Electronic data submittal forms for use in preparing a customized form specifically for your organization are available from the WECC web site or by e-mail from WECC Staff at the e-mail address specified on the WECC web site.

1.3 Data Retention

Data will be retained in electronic form for at least four years. The retention period will be evaluated before expiration of four years to determine if a longer retention period is necessary. If the data are being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

1.4. Additional Compliance Information
For purposes of applying the sanctions specified in the WECC Reliability Standard for violations of this criterion, the “Sanction Measure” is Normal Path Rating and the “Specified Period” is the four most recent calendar years. The sanctions shall be assessed on an annual basis, but for purposes of determining the applicable column in the Sanctions Table, all occurrences within the specified period of the most recent calendar year and all immediately preceding consecutive calendar years in which at least one instance of non-compliance occurred shall be considered. (Source: Sanctions)

2. Levels of Non-Compliance

Sanction Measure: Normal Path Rating

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 The Responsible Entity certifies that it has developed and documented a TMIP (8a from Certification Form) and certifies that it is fulfilling only one of the following two requirements:

- Performing maintenance, testing and inspections in accordance with its TMIP (8b from Certification Form), or
- Maintaining maintenance and inspection records as required by the Transmission Maintenance Standard (8c from Certification Form).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 The Responsible Entity certifies that it has developed and documented a TMIP (8a from Certification Form) and has not certified that it is fulfilling the following two requirements:

- Performing maintenance, testing and inspections in accordance with its TMIP (8b from Certification Form), and
- Maintaining maintenance and inspection records as required by the Transmission Maintenance Standard (8c from Certification Form).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 The Responsible Entity does not have a TMIP but has submitted a mitigation plan to achieve full compliance.

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 The Responsible Entity does not have a TMIP and has not submitted a mitigation plan to achieve full compliance.

E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
</table>

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Sanction Table
Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
<thead>
<tr>
<th>Level of Non-compliance</th>
<th>Number of Occurrences at a Given Level within Specified Period</th>
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<tbody>
<tr>
<td></td>
<td>1</td>
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<tr>
<td>Level 1</td>
<td>Letter (A)</td>
</tr>
<tr>
<td>Level 2</td>
<td>Letter (B)</td>
</tr>
<tr>
<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
</tbody>
</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and...
one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Responsible Entity has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.
<table>
<thead>
<tr>
<th>PATH NAME*</th>
<th>Path Number</th>
<th>Operating Agent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta – British Columbia</td>
<td>1</td>
<td>BCTC/AESO</td>
</tr>
<tr>
<td>Northwest – British Columbia</td>
<td>3</td>
<td>BCTC/BPA</td>
</tr>
<tr>
<td>West of Cascades – North</td>
<td>4</td>
<td>BPA</td>
</tr>
<tr>
<td>West of Cascades – South</td>
<td>5</td>
<td>BPA</td>
</tr>
<tr>
<td>West of Hatwai</td>
<td>6</td>
<td>AVA/BPA</td>
</tr>
<tr>
<td>Montana to Northwest</td>
<td>8</td>
<td>NWMT</td>
</tr>
<tr>
<td>Idaho to Northwest</td>
<td>14</td>
<td>IPC</td>
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<td>South of Los Banos or Midway - Los Banos</td>
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<td>CISO</td>
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<td>Idaho – Sierra</td>
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<td>SPP</td>
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<td>IPC</td>
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<td>CISO</td>
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<td>Intmttn. Power Project DC Line</td>
<td>27</td>
<td>LADWP</td>
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<td>30</td>
<td>WAPA</td>
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<td>TOT 2A</td>
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<td>WAPA</td>
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<td>32</td>
<td>SPP/LADWP</td>
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<td>TOT 2C</td>
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<td>NEVP</td>
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<td>Southern New Mexico (NM1)</td>
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<td>EPE</td>
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<td>Northern New Mexico (NM2)</td>
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<td>PNM</td>
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<td>APS</td>
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<td>APS</td>
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<td>Southern Navajo</td>
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<td>APS</td>
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<td>Brownlee East</td>
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<td>IPC</td>
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* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in this Standard and as set out below:

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**Normal Path Rating** is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

**WECC Table 2** means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

EXCUSE OF PERFORMANCE

A. Excused Non-Compliance

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

B. Specific Excuses

1. Governmental Order

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. Order of Reliability Coordinator

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security
Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Standard. Reasonable efforts shall
include shedding load, disconnecting facilities, altering
generation patterns or schedules on the transmission
system, or purchasing energy or capacity, except to the
extent that the Reliability Entity demonstrates to the WECC
Staff and/or the RCC that in the particular circumstances
such action would have been unreasonable. Reasonable
efforts shall not include the settlement of any strike,
lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by
an Extraordinary Contingency shall immediately notify the
WECC of such contingency and shall report daily or at
such other interval prescribed by the WECC the efforts
being undertaken to mitigate the effects of such
contingency and to bring the Reliability Entity back into
full compliance.

c. An Extraordinary Contingency means any act of God,
actions by a non-affiliated third party, labor disturbance, act
of the public enemy, war, insurrection, riot, fire, storm or
flood, earthquake, explosion, accident to or breakage,
failure or malfunction of machinery or equipment, or any
other cause beyond the Reliability Entity’s reasonable
control; provided that prudent industry standards (e.g.,
maintenance, design, operation) have been employed; and
provided further that no act or cause shall be considered an
Extraordinary Contingency if such act or cause results in
any contingency contemplated in any WECC Reliability
Standard (e.g., the “Most Severe Single Contingency” as
defined in the WECC Reliability Criteria or any lesser
contingency).

5. Participation in Field Testing

Any action taken or not taken by the Reliability Entity in
conjunction with the Reliability Entity’s involvement in the field
testing (as approved by either the WECC Operating Committee or
the WECC Planning Coordination Committee) of a new reliability
criterion or a revision to an existing reliability criterion where such
action or non-action causes the Reliability Entity’s non-compliance
with the reliability criterion to be replaced or revised by the
criterion being field tested; provided that Reliability Entity’s non-
compliance is the result of Reliability Entity’s reasonable efforts to
participate in the field testing.
A. Introduction

1. Title: Reliability Responsibilities and Authorities
2. Number: TOP-001-1
3. Purpose:
   To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. Applicability
   4.1. Balancing Authorities
   4.2. Transmission Operators
   4.3. Generator Operators
   4.4. Distribution Providers
   4.5. Load Serving Entities

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency 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 took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or
transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator’s reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator’s reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator 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 informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each 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 rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each 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 notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

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 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 Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

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 supporting compliance data.

1.4. **Additional Compliance Information**
None.

2.  **Levels of Non-Compliance for a Balancing Authority:**

2.1. **Level 1:** Not applicable.

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 Did not comply with a Reliability Coordinator’s or Transmission Operator’s reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3.  **Levels of Non-Compliance for a Transmission Operator**

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 documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator’s reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4.  **Levels of Non-Compliance for a Generator Operator:**
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 or Transmission Operator’s reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. **Levels of Non-Compliance for a Distribution Provider or Load Serving Entity**

5.1. **Level 1**: Not applicable.

5.2. **Level 2**: Not applicable.

5.3. **Level 3**: Not applicable.

5.4. **Level 4**: Did not comply with a Transmission Operator’s reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. **Regional Differences**

None identified.

**Version History**

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A. Introduction

1. Title: Normal Operations Planning
2. Number: TOP-002-2
3. Purpose: Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. Applicability
   4.1. Balancing Authority.
   4.2. Transmission Operator.
   4.3. Generator Operator.
   4.4. Load Serving Entity.
   4.5. Transmission Service Provider.

5. Effective Date: January 1, 2007
   Six months after effective date of VAR-001-1.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1
Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)
R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.


R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)
M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement 16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

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 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 Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).
For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as 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 supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. **Level 1**: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

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 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. **Level 1**: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. **Level 2**: Not applicable.

3.3. **Level 3**: One or more of Bulk Electric System studies were not made available as specified in R11.

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 Did not maintain an updated set of current-day plans as specified in R1.
3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.
3.4.3 Studies not updated to reflect current system conditions as specified in R11.
3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

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 verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

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A. Introduction

1. **Title:** Normal Operations Planning
2. **Number:** TOP-002-2a
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**
   4.1. Balancing Authority.
   4.2. Transmission Operator.
   4.3. Generator Operator.
   4.4. Load Serving Entity.
   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:


R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.


R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures
M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)
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 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 Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as 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 supporting compliance data.

1.4. Additional Compliance Information

None.
2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

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 Did not maintain an updated set of current-day plans as specified in R1.
- 2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

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 Did not maintain an updated set of current-day plans as specified in R1.
- 3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.
- 3.4.3 Studies not updated to reflect current system conditions as specified in R11.
- 3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

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 verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.
- 4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.
- 4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
5.2. **Level 2**: Not applicable.

5.3. **Level 3**: Not applicable.

5.4. **Level 4**: Not applicable.

E. **Regional Differences**

None identified.

**Version History**

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Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a “unique” study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have “a” study that can be applied to it, but it is not necessary to generate a “unique” study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a “study”? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, “to determine SOLs” as used in the first sentence of Requirement R11 mean the “determination of system operating limits” or does it mean the “identification of potential SOL violations?”

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential “exceedances” of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.
A. Introduction

1. Title: Planned Outage Coordination
2. Number: TOP-003-0
3. Purpose: Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. Applicability
   4.1. Generator Operators.
   4.2. Transmission Operators.
   4.3. Balancing Authorities.
   4.4. Reliability Coordinators.

5. Effective Date: April 1, 2005

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.
   R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
   R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
   R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.
D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

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 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.
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A. Introduction

1. Title: Planned Outage Coordination
2. Number: TOP-003-1
3. Purpose: Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. Applicability
   4.1. Generator Operators.
   4.2. Transmission Operators.
   4.3. Balancing Authorities.
   4.4. Reliability Coordinators.

5. Proposed Effective Date:
   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.
   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.
   R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
   R1.2. Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
   R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.
2. **Violation Severity Levels:**

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<td>The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).</td>
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<td>R1.1</td>
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<td>N/A</td>
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<td>The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.</td>
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<td>The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.</td>
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<td>R1.3</td>
<td>N/A</td>
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<td>The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.</td>
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<td>R2</td>
<td>The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.</td>
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<td>The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.</td>
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<td>R3</td>
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<td>The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.</td>
<td>The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.</td>
<td>The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.</td>
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E. Regional Variances

None identified.

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1. Title: Transmission Operations
2. Number: TOP-004-2
3. Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. Applicability:
   4.1. Transmission Operators
5. Proposed Effective Date: Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:
   R6.1. Monitoring and controlling voltage levels and real and reactive power flows.
   R6.2. Switching transmission elements.
   R6.3. Planned outages of transmission elements.
   R6.4. Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, 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, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.
M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.
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 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 Transmission Operator shall keep 90 days of historical data for Measure 1.
Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.
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 supporting compliance data

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.
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 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

**E. Regional Differences**

None identified.

**Version History**

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<td>1</td>
<td>November 1, 2006</td>
<td>Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006</td>
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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: May 13, 2009

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.

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<td>May 13, 2009</td>
<td>FERC Approved – Updated Effective Date and Footer</td>
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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.
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-005-1.1a
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.

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<td>1.1a</td>
<td>November 5, 2009</td>
<td>Added Appendix 2 – Interpretation of R3 approved by BOT on November 5, 2009</td>
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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.
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.
Appendix 2

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<td><strong>TOP-005-1 Requirement R3</strong></td>
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<td>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.</td>
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*The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded special protection systems.* [Underline added for emphasis.]

**IRO-005-1 Requirement R12**

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. [Underline added for emphasis.]

**PRC-012-0 Requirements R1 and R1.3**

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

**Background Information for Interpretation**

The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”

The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).
IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

**Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.
A. Introduction

1. **Title:** Operational Reliability Information
2. **Number:** TOP-005-2
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. Purchasing Selling Entities.
5. **Proposed Effective Date:**
   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. 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.”

R2. 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 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. 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 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. **Violation Severity Levels:**

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E. Regional Variances

None identified.

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Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

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: Monitoring System Conditions
2. Number: TOP-006-1
3. Purpose:

To ensure critical reliability parameters are monitored in real-time.

4. Applicability

4.1. Transmission Operators.
4.2. Balancing Authorities.
4.3. Generator Operators.
4.4. Reliability Coordinators.

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.
C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system’s near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

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 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 noncompliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

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 supporting compliance data.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Reliability Coordinators:

2.1. Level 1: Not applicable.

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 Does not monitor all of the applicable items listed in Requirement 2.

2.4.2 Did not have the information specified in R4.
2.4.3 Did not bring to the attention of its operators, important deviations in operating conditions and the need for corrective actions. (Requirement 5)

2.4.4 No evidence it monitors system frequency. (Requirement 7)

3. Levels of Non-Compliance for Generator Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: Did not inform its Host Balancing Authority and/or the Transmission Operator of all generation resources available for use. (R1.1)

4. Levels of Non-Compliance for Transmission Operators and Balancing Authorities:

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 inform the Reliability Coordinator and/or other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use in accordance with R1.2.

4.4.2 Does not monitor all the applicable items listed in R2.

4.4.3 Did not have the information specified in R4.

4.4.4 Does not have monitoring to bring to the attention of operating personnel important deviations in operating conditions and the need for corrective actions as specified in R5.

4.4.5 No evidence it monitors system frequency. (R7).

E. Regional Differences

None identified.

Version History

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<thead>
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<tr>
<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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</table>
A. Introduction

1. **Title:** Monitoring System Conditions
2. **Number:** TOP-006-2
3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.
4. **Applicability**
   4.1. Transmission Operators.
   4.2. Balancing Authorities.
   4.3. Generator Operators.
   4.4. Reliability Coordinators.

5. **Proposed Effective Date:**
   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.
   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.
   
   R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
   
   R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
   
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
   
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.
   
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern.
   
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system’s near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

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 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 Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

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 supporting compliance data.

1.4. **Additional Compliance Information**

None.
2. Violation Severity Levels:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.</td>
</tr>
<tr>
<td>R1.1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.</td>
</tr>
<tr>
<td>R1.2</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.</td>
</tr>
<tr>
<td>R2</td>
<td>N/A</td>
<td>The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.</td>
<td>The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.</td>
<td>The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Lower</td>
<td>Moderate</td>
<td>High</td>
<td>Severe</td>
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<tr>
<td>-------------</td>
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</tr>
<tr>
<td>R3</td>
<td>The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.</td>
</tr>
<tr>
<td>R4</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity has either weather forecasts or past load patterns, available to predict the system’s near-term load pattern, but not both.</td>
<td>The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system’s near-term load pattern.</td>
</tr>
<tr>
<td>R5</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.</td>
<td>The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.</td>
</tr>
<tr>
<td>R6</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.</td>
</tr>
<tr>
<td>R7</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to monitor system frequency.</td>
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</table>
E. Regional Variances

None identified.

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<tr>
<td>2</td>
<td></td>
<td>Modified R4</td>
<td>Revised</td>
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<td></td>
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<td>Modified M4</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Modified Data Retention for M4</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Replaced Levels of Non-compliance with the</td>
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<td></td>
<td></td>
<td>Levels (VSLs)</td>
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A. Introduction

1. Title: Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
2. Number: TOP-007-0
3. Purpose: This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.
4. Applicability:
   4.1. Transmission Operators.
   4.2. Reliability Coordinators.
5. Effective Date: April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.
M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.
M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:
1.1.1. System instability.
1.1.2. Unacceptable system dynamic response or equipment tripping.
1.1.3. Voltage levels in violation of applicable emergency limits.
1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.
1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe
The reset period is monthly.

1.3. Data Retention
The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

<table>
<thead>
<tr>
<th>Percentage by which IROL or SOL that has become an IROL is exceeded*</th>
<th>Limit exceeded for more than 30 minutes, up to 35 minutes.</th>
<th>Limit exceeded for more than 35 minutes, up to 40 minutes.</th>
<th>Limit exceeded for more than 40 minutes, up to 45 minutes.</th>
<th>Limit exceeded for more than 45 minutes.</th>
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</thead>
<tbody>
<tr>
<td>Greater than 0%, up to and including 5%</td>
<td>Level 1</td>
<td>Level 2</td>
<td>Level 2</td>
<td>Level 3</td>
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<tr>
<td>Greater than 5%, up to and including 10%</td>
<td>Level 2</td>
<td>Level 2</td>
<td>Level 3</td>
<td>Level 3</td>
</tr>
<tr>
<td>Greater than 10%, up to and including 15%</td>
<td>Level 2</td>
<td>Level 3</td>
<td>Level 3</td>
<td>Level 4</td>
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<tr>
<td>Greater than 15%, up to and including 20%</td>
<td>Level 3</td>
<td>Level 3</td>
<td>Level 4</td>
<td>Level 4</td>
</tr>
<tr>
<td>Greater than 20%, up to and including 25%</td>
<td>Level 3</td>
<td>Level 4</td>
<td>Level 4</td>
<td>Level 4</td>
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<tr>
<td>Greater than 25%</td>
<td>Level 4</td>
<td>Level 4</td>
<td>Level 4</td>
<td>Level 4</td>
</tr>
</tbody>
</table>

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).
E. Regional Differences

None identified.

Version History

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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<th>Completion Date</th>
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<tbody>
<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 21, 2007</td>
</tr>
<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 16, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 25, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
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Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for TOP-STD-007-0. TOP-007-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when TOP-STD-007-0 was approved as a NERC reliability standard.

This draft standard incorporates the following refinements to the first draft of TOP-007-WECC-1 in response to comments received during the first comment period that ended November 5, 2007 and the second comment period that ended January 2, 2008.

1. Refine R1 to remove the requirement to return a path to within its limit in 20 minute for SOLs based upon Transient Stability and Voltage Stability.
2. Refine R2 to limit the compliance period for the Net Scheduled Interchange to the real-time schedules for the next hour.
3. Refine R2 to permit 30 minutes to adjust Net Scheduled Interchange when SOLs reduce within 20 minutes of the start of the hour.
4. Change M2 based upon the refinements to R2.
5. Base the violation severity levels for R2 upon magnitude.

The WECC Operating Committee approved the TOP-007-WECC-1 standard as a permanent replacement standard for TOP-STD-007-0 on March 6, 2008. This posting of the standard is for ballot by the WECC Board of Directors. The Operating Committee recommends that the WECC Board of Directors approve the TOP-007-WECC-1 as a permanent replacement standard for TOP-STD-007-0. In addition, the Operating Committee recommends that the WECC Board of Directors submit the standard to the NERC and FERC for approval.
Justification for a Regional Standard

The NERC standard (TOP-STD-007-0) has requirements for reducing actual flows to within System Operating Limits (SOL) on Major WECC Transfer Paths in the Bulk Electric System. The major paths listed in the Table titled “Major WECC Transfer Paths in the Bulk Electric System” are significant components for reliable delivery of power in the Western Interconnection. System Operating Limits for these paths are critical because they transfer energy from remotely located generation to population/load centers. The entities of the Western Interconnection through studies and operation see the need for optimizing the capacity of these paths. The lack of redundant transmission in these corridors raises the level of scrutiny for these paths; therefore, this standard is designed to add emphasis to reducing flows to within SOL to maintain reliable Western Interconnection operation.

NERC TOP-007-0 (R2) requires the Transmission Operator to return its transmission path flows to within Interconnection Reliability Operating Limits (IROL) as soon as possible, but no longer than 30 minutes following a contingency or event. This requirement applies only to those limits that are defined as IROL. Depending on the current system conditions, the limits for the paths identified in this TOP-007-WECC-1 standard are SOL that would not result in cascading outages. There is no NERC requirement to return the transmission system to within SOL limits, only a requirement to report to the Reliability Coordinator. TOP-007-WECC-1 specifically applies to the major paths in the Western Interconnection regardless of whether the limit is defined as an IROL or the less severe SOL.

In Order No. 693 and Docket No. RR07-11-000, the FERC expressed concern that TOP-007-0 could be interpreted as allowing a system operator to respect IROLs in one of two ways: (1) allowing IROL to be exceeded during normal operations, i.e., prior to a contingency, provided that corrective actions are taken within 30 minutes; or (2) allowing IROL to be exceeded only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. FERC explained that the system could be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation. FERC directed NERC to conduct a survey on IROL practices and actual operating experiences of managing within IROL. The survey results will provide guidance on the frequency, duration, and magnitude of IROL violations and whether these IROL violations occur during normal or contingency conditions.

WECC and NERC responded to FERC’s June 8, 2007 Order (Docket No. RR007-11-000) in its compliance filing of July 9, 2007. The compliance filing document is posted with this standard for reference. On November 2, 2007, FERC accepted NERC’s and WECC’s filing and indicated that the filing satisfactorily responds to the Commission’s directive, Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (2007) at P 108.
<table>
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<td><strong>Anticipated Actions</strong></td>
<td><strong>Anticipated Date</strong></td>
</tr>
<tr>
<td>2. WECC Board ballots proposed standard</td>
<td>April 16-18, 2008</td>
</tr>
<tr>
<td>3. Drafting Team to review and respond to NERC industry comments</td>
<td>May 2008</td>
</tr>
<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
</tr>
<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
</tr>
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</table>
Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.
A. Introduction

1. Title: System Operating Limits
2. Number: TOP-007-WECC-1
3. Purpose: When actual flows on Major WECC Transfer Paths exceed System Operating Limits (SOL), their associated schedules and actual flows are not exceeded for longer than a specified time.

4. Applicability

4.1. Transmission Operators for the transmission paths in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” provided at:
(http://www.wecc.biz/documents/library... The Table titled “Major WECC Transfer Paths in the Bulk Electric System” is Attachment 2 – TOP-007-WECC-1 in this document. The Table will be posted on the WECC website.)

5. Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R.1. When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R.2. The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path’s SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply. [Violation Risk Factor: Low] [Time Horizon: Real-time Operations]

R2.1. If the path SOL decreases within 20 minutes before the start of the hour, the Transmission Operator shall adjust the Net Scheduled Interchange within 30 minutes to the new SOL value. Net Scheduled Interchange exceeding the new SOL during this 30-minute period will not be a violation of R2.

C. Measures

M1. Evidence that actual power flow has not exceeded the SOL for the specified time limit in R1.

M2. Evidence that Net Scheduled Interchange has not exceeded the SOL when the Transmission Operator implements real-time schedules as required by R2.

M2.1 Evidence that Net Scheduled Interchange was at or below the new SOL within 30-minutes of when the SOL decreased.

D. Compliance

1. Compliance Monitoring Process
1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-report for each incident within three-business day
- Self-report quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

Reset Period: One calendar month.

1.3 Data Retention

The Transmission Operators shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

2. Violation Severity Levels

For Requirement R1:

2.1. **Lower:** There shall be a Lower Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.2. **Moderate:** There shall be a Moderate Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.3. **High:** There shall be a High Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.4. **Severe:** There shall be a Severe Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

For Requirement R2:

2.1. **Lower:** There shall be a Lower Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above the path’s SOL but is less than or equal to 105% of the path’s SOL.

2.2. **Moderate:** There shall be a Moderate Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 105% of the path’s SOL but less than or equal to 110% of the path’s SOL.
2.3. **High:** There shall be a High Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 110% of the path’s SOL.

2.4 **Severe:** None

### Version History – Shows Approval History and Summary of Changes in the Action Field

<table>
<thead>
<tr>
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<th>Action</th>
<th>Change Tracking</th>
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<td>January 1, 2008</td>
<td>Permanent Replacement Standard for TOP-STD-007-0</td>
<td></td>
</tr>
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</table>
### Attachment 1 – TOP-007-WECC-1

**Violation Severity Level Table**

<table>
<thead>
<tr>
<th>Percentage by which SOL is exceeded*</th>
<th>Limit exceeded for more than 30 minutes, up to 35 minutes</th>
<th>Limit exceeded for more than 35 minutes, up to 40 minutes</th>
<th>Limit exceeded for more than 40 minutes, up to 45 minutes</th>
<th>Limit exceeded for more than 45 minutes</th>
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</thead>
<tbody>
<tr>
<td>greater than 0%, up to and including 5%</td>
<td>Lower</td>
<td>Moderate</td>
<td>Moderate</td>
<td>High</td>
</tr>
<tr>
<td>greater than 5%, up to and including 10%</td>
<td>Moderate</td>
<td>Moderate</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>greater than 10%, up to and including 15%</td>
<td>Moderate</td>
<td>High</td>
<td>High</td>
<td>Severe</td>
</tr>
<tr>
<td>greater than 15%, up to and including 20%</td>
<td>High</td>
<td>High</td>
<td>Severe</td>
<td>Severe</td>
</tr>
<tr>
<td>greater than 20%, up to and including 25%</td>
<td>High</td>
<td>Severe</td>
<td>Severe</td>
<td>Severe</td>
</tr>
<tr>
<td>greater than 25%</td>
<td>Severe</td>
<td>Severe</td>
<td>Severe</td>
<td>Severe</td>
</tr>
</tbody>
</table>

* Measured after 30 continuous minutes of actual flows in excess of SOL.
## Major WECC Transfer Paths in the Bulk Electric System

(Revised September 1, 2007)

<table>
<thead>
<tr>
<th>PATH NAME*</th>
<th>Path Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alberta – British Columbia</td>
<td>1</td>
</tr>
<tr>
<td>2. Northwest – British Columbia</td>
<td>3</td>
</tr>
<tr>
<td>3. West of Cascades – North</td>
<td>4</td>
</tr>
<tr>
<td>4. West of Cascades – South</td>
<td>5</td>
</tr>
<tr>
<td>5. West of Hawaii</td>
<td>6</td>
</tr>
<tr>
<td>6. Montana to Northwest</td>
<td>8</td>
</tr>
<tr>
<td>7. Idaho to Northwest</td>
<td>14</td>
</tr>
<tr>
<td>8. South of Los Banos or Midway- Los Banos</td>
<td>15</td>
</tr>
<tr>
<td>9. Idaho – Sierra</td>
<td>16</td>
</tr>
<tr>
<td>10. Borah West</td>
<td>17</td>
</tr>
<tr>
<td>11. Idaho – Montana</td>
<td>18</td>
</tr>
<tr>
<td>12. Bridger West</td>
<td>19</td>
</tr>
<tr>
<td>13. Path C</td>
<td>20</td>
</tr>
<tr>
<td>14. Southwest of Four Corners</td>
<td>22</td>
</tr>
<tr>
<td>15. PG&amp;E – SPP</td>
<td>24</td>
</tr>
<tr>
<td>16. Northern – Southern California</td>
<td>26</td>
</tr>
<tr>
<td>17. Intmtn. Power Project DC Line</td>
<td>27</td>
</tr>
<tr>
<td>18. TOT 1A</td>
<td>30</td>
</tr>
<tr>
<td>19. TOT 2A</td>
<td>31</td>
</tr>
<tr>
<td>20. Pavant – Gonder 230 kV</td>
<td>32</td>
</tr>
<tr>
<td>Intermountain – Gonder 230 kV</td>
<td></td>
</tr>
<tr>
<td>21. TOT 2B</td>
<td>34</td>
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<tr>
<td>22. TOT 2C</td>
<td>35</td>
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<tr>
<td>23. TOT 3</td>
<td>36</td>
</tr>
<tr>
<td>24. TOT 5</td>
<td>39</td>
</tr>
<tr>
<td>25. SDGE – CFE</td>
<td>45</td>
</tr>
<tr>
<td>26. West of Colorado River (WOR)</td>
<td>46</td>
</tr>
<tr>
<td>27. Southern New Mexico (NM1)</td>
<td>47</td>
</tr>
<tr>
<td>28. Northern New Mexico (NM2)</td>
<td>48</td>
</tr>
<tr>
<td>29. East of the Colorado River (EOR)</td>
<td>49</td>
</tr>
<tr>
<td>30. Cholla – Pinnacle Peak</td>
<td>50</td>
</tr>
<tr>
<td>31. Southern Navajo</td>
<td>51</td>
</tr>
<tr>
<td>32. Brownlee East</td>
<td>55</td>
</tr>
<tr>
<td>33. Lugo – Victorville 500 kV</td>
<td>61</td>
</tr>
<tr>
<td>34. Pacific DC Intertie</td>
<td>65</td>
</tr>
<tr>
<td>35. COI</td>
<td>66</td>
</tr>
<tr>
<td>36. North of John Day cutplane</td>
<td>73</td>
</tr>
<tr>
<td>37. Alturas</td>
<td>76</td>
</tr>
<tr>
<td>38. Montana Southeast</td>
<td>80</td>
</tr>
<tr>
<td>39. SCIT**</td>
<td></td>
</tr>
<tr>
<td>40. COI/PDCI – North of John Day cutplane**</td>
<td></td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
A. Introduction

1. Title: Response to Transmission Limit Violations
2. Number: TOP-008-1
3. Purpose: To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. Applicability
   4.1. Transmission Operators.
5. Effective Date: January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility 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 notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL 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 confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

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 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 Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.
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 data.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

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 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

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<th>Change Tracking</th>
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<td>Errata</td>
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<tr>
<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Revised</td>
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</table>
A. Introduction

1. Title: Operating Transfer Capability
2. Number: TOP-STD-007-0
3. Purpose: Regional Reliability Standard to ensure the Operating Transfer Capability limits requirements of the Western Interconnection are not exceeded.

4. Applicability

4.1. This criterion applies to each Transmission Operator of a transmission path in the Attachment A – WECC Table 2 (Source: Participants Subject to Criterion)

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1. Operating Transfer Capability Limit Criteria

Actual power flow and net scheduled power flow over an interconnection or transfer path shall be maintained within Operating Transfer Capability Limits (“OTC”). The OTC is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- An interconnection from one Transmission Operator area to another Transmission Operator area; or

- A transfer path within a Transmission Operator area.

The net schedule over an interconnection or transfer path within a Transmission Operator area shall not exceed the OTC, regardless of the prevailing actual power flow on the interconnection or transfer path.

a. Operating limits. No elements within the interconnection shall be scheduled above continuous operating limits. An element is defined as any generating unit, transmission line, transformer, bus, or piece of electrical equipment involved in the transfer of power within an interconnection.

b. Stability. The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the WECC Reliability Criteria for Transmission System Planning. If a single event could cause loss of multiple elements, these shall be considered in lieu of a single element outage. This could occur in exceptional cases such as two lines on the same right-of-way next to an airport. In either case, loss of either single or multiple elements should not cause uncontrolled, widespread collapse of the interconnected power system. For purposes of this
Section, stability shall include transient stability, post transient stability or dynamic stability whichever is most limiting to OTC.

c. System contingency response. Following the outage and before adjustments can be made:

(i) No remaining element shall exceed its short-time emergency rating.

(ii) The steady-state system voltages shall be within emergency limits.

The limiting event shall be determined by conducting power flow and stability studies while simulating various operating conditions. These studies shall be updated as system configurations introduce significant changes in the interconnection. (Source: WECC Criterion)

C. Measures

WM1.

Actual power flow on all transmission paths shall at no time exceed the OTC for more than 20 minutes for paths that are stability limited, or for more than 30 minutes for paths that are thermally limited. (Source: Compliance Standard)

D. Compliance

1. Compliance Monitoring Process

   1.1 Compliance Monitoring Responsibility
   Western Electricity Coordinating Council (WECC)

   1.2 Compliance Monitoring Period
   At Occurrence and Quarterly
   By no later than 5:00 p.m. Mountain Time on the first Business Day following the day on which an instance of non-compliance occurs (or such other date specified in Form A.4(a)), a Transmission Operator identified in Section A.4.1 shall submit to the WECC office operating transfer capability data in Form A.4(a) (available on the WECC web site) for each such instance of non-compliance. On or before the tenth day of each calendar quarter (or such other date specified in Form A.4(b)), the Transmission Operator identified in Section A.4.1 (including Transmission Operators with no reported instances of non-compliance) shall submit to the WECC office a completed OTC summary compliance Form A.4(b) (available on the WECC web site) for the immediately preceding calendar quarter.

   1.3 Data Retention
   Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

   1.4. Additional Compliance Information
For purposes of applying the sanctions specified in the WECC Reliability Standard for violations of this criterion, the “Sanction Measure” is Normal Path Rating and the “Specified Period” is the most recent calendar month. (Source: Sanctions)

## 2. Levels of Non-Compliance

**Sanction Measure:** Normal Path Rating

For each separate incident violating the OTC compliance Standard, the level of the violation shall be as set forth in the following table: (Source: Non-Compliance Levels)

<table>
<thead>
<tr>
<th>Thermal Limited Paths:</th>
<th>Limit exceeded for more than 30 minutes, up to 35 minutes</th>
<th>Limit exceeded for more than 35 minutes, up to 40 minutes</th>
<th>Limit exceeded for more than 40 minutes, up to 45 minutes</th>
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<tr>
<td>Stability Limited Paths:</td>
<td>Limit exceeded for more than 20 minutes, up to 25 minutes</td>
<td>Limit exceeded for more than 25 minutes, up to 30 minutes</td>
<td>Limit exceeded for more than 30 minutes, up to 35 minutes</td>
<td>Limit exceeded for more than 35 minutes</td>
</tr>
<tr>
<td>Percentage by which net scheduled or actual flows exceed OTC*</td>
<td>Level 1</td>
<td>Level 2</td>
<td>Level 2</td>
<td>Level 3</td>
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<td>Level 2</td>
<td>Level 2</td>
<td>Level 3</td>
<td>Level 3</td>
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<tr>
<td>greater than 5%, up to and including 10%</td>
<td>Level 2</td>
<td>Level 3</td>
<td>Level 3</td>
<td>Level 4</td>
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<td>greater than 10%, up to and including 15%</td>
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<tr>
<td>greater than 20%, up to and including 25%</td>
<td>Level 3</td>
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<td>Level 4</td>
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<td>greater than 25%</td>
<td>Level 4</td>
<td>Level 4</td>
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<td>Level 4</td>
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* measured after 20 continuous minutes of net scheduled or actual flows in excess of OTC.

### E. Regional Differences

**Version History** – Shows Approval History and Summary of Changes in the Action Field

| Version | Date | Action | Change Tracking |
|---------|------|--------|-----------------|-----------------|

Page 3 of 10
Sanction Table
Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
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<tr>
<td>Level 1</td>
<td>Letter (A)</td>
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<tr>
<td>Level 2</td>
<td>Letter (B)</td>
</tr>
<tr>
<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
</tbody>
</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and

---

1 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.
## Table 2
Existing WECC Transfer Paths (BPTP)
(Revised February 1, 2006)

<table>
<thead>
<tr>
<th>PATH NAME*</th>
<th>Path Number</th>
<th>Operating Agent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta – British Columbia</td>
<td>1</td>
<td>BCTC/AESO</td>
</tr>
<tr>
<td>Northwest – British Columbia</td>
<td>3</td>
<td>BCTC/BPA</td>
</tr>
<tr>
<td>West of Cascades – North</td>
<td>4</td>
<td>BPA</td>
</tr>
<tr>
<td>West of Cascades – South</td>
<td>5</td>
<td>BPA</td>
</tr>
<tr>
<td>West of Hatwai</td>
<td>6</td>
<td>AVA/BPA</td>
</tr>
<tr>
<td>Montana to Northwest</td>
<td>8</td>
<td>NWMT</td>
</tr>
<tr>
<td>Idaho to Northwest</td>
<td>14</td>
<td>IPC</td>
</tr>
<tr>
<td>South of Los Banos or Midway- Los Banos</td>
<td>15</td>
<td>CISO</td>
</tr>
<tr>
<td>Idaho – Sierra</td>
<td>16</td>
<td>SPP</td>
</tr>
<tr>
<td>Borah West</td>
<td>17</td>
<td>IPC</td>
</tr>
<tr>
<td>Idaho – Montana</td>
<td>18</td>
<td>NWMT</td>
</tr>
<tr>
<td>Bridger West</td>
<td>19</td>
<td>PAC</td>
</tr>
<tr>
<td>Path C</td>
<td>20</td>
<td>PAC</td>
</tr>
<tr>
<td>Southwest of Four Corners</td>
<td>22</td>
<td>APS</td>
</tr>
<tr>
<td>PG&amp;E – SPP</td>
<td>24</td>
<td>CISO</td>
</tr>
<tr>
<td>Northern – Southern California</td>
<td>26</td>
<td>CISO</td>
</tr>
<tr>
<td>Intmtn. Power Project DC Line</td>
<td>27</td>
<td>LADWP</td>
</tr>
<tr>
<td>TOT 1A</td>
<td>30</td>
<td>WAPA</td>
</tr>
<tr>
<td>TOT 2A</td>
<td>31</td>
<td>WAPA</td>
</tr>
<tr>
<td>Pavant – Gonder 230 kV Intermountain – Gonder 230 kV</td>
<td>32</td>
<td>SPP/LADWP</td>
</tr>
<tr>
<td>TOT 2B</td>
<td>34</td>
<td>PAC</td>
</tr>
<tr>
<td>TOT 2C</td>
<td>35</td>
<td>NEVP</td>
</tr>
<tr>
<td>TOT 3</td>
<td>36</td>
<td>WAPA</td>
</tr>
<tr>
<td>TOT 5</td>
<td>39</td>
<td>WAPA</td>
</tr>
<tr>
<td>SDGE – CFE</td>
<td>45</td>
<td>CISO/CFE</td>
</tr>
<tr>
<td>West of Colorado River (WOR)</td>
<td>46</td>
<td>CISO</td>
</tr>
<tr>
<td>Southern New Mexico (NM1)</td>
<td>47</td>
<td>EPE</td>
</tr>
<tr>
<td>Northern New Mexico (NM2)</td>
<td>48</td>
<td>PNM</td>
</tr>
<tr>
<td>East of the Colorado River (EOR)</td>
<td>49</td>
<td>APS</td>
</tr>
<tr>
<td>Cholla – Pinnacle Peak</td>
<td>50</td>
<td>APS</td>
</tr>
<tr>
<td>Southern Navajo</td>
<td>51</td>
<td>APS</td>
</tr>
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<td>Brownlee East</td>
<td>55</td>
<td>IPC</td>
</tr>
<tr>
<td>Lugo – Victorville 500 kV</td>
<td>61</td>
<td>CISO/LDWP</td>
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<tr>
<td>Pacific DC Intertie</td>
<td>65</td>
<td>BPA/LADWP</td>
</tr>
<tr>
<td>COI</td>
<td>66</td>
<td>BPA/CISO</td>
</tr>
<tr>
<td>North of John Day cutplane</td>
<td>73</td>
<td>BPA</td>
</tr>
<tr>
<td>Alturas</td>
<td>76</td>
<td>SPP</td>
</tr>
<tr>
<td>Montana Southeast</td>
<td>80</td>
<td>NWMT</td>
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<tr>
<td>SCIT**</td>
<td></td>
<td>CISO</td>
</tr>
<tr>
<td>COI/PDCI – North of John Day cutplane**</td>
<td></td>
<td>BPA</td>
</tr>
</tbody>
</table>

* For an explanation of terms, path numbers, and definition for the paths refer to WECC’s Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC’s Path Rating Catalog.
DEFINITIONS

Unless the context requires otherwise, all capitalized terms shall have the meanings assigned in this Standard and as set out below:

**Business Day** means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**Normal Path Rating** is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.

**Operating Transfer Capability Limit** or **OTC** means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.

**WECC Table 2** means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

EXCUSE OF PERFORMANCE

A. **Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.
B. Specific Excuses

1. Governmental Order

The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. Order of Reliability Coordinator

The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. Protection of Facilities

Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the
RCC that in the particular circumstances such action would have been unreasonable.

4. Extraordinary Contingency

a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Standard. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).
5. Participation in Field Testing

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
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: May 13, 2009

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-re callable 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.
R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R1 and TPL-001-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
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

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>February 8, 2005</td>
<td>BOT Approval</td>
<td>Revised</td>
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<td>0</td>
<td>June 3, 2005</td>
<td>Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2</td>
<td>Errata</td>
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<td>0</td>
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<td>Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.</td>
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<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to “0.1”</td>
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<td>0.1</td>
<td>May 13, 2009</td>
<td>FERC Approved – Updated Effective Date and Footer</td>
<td>Revised</td>
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### Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>System Limits or Impacts</th>
<th>Cascading Outages</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>All Facilities in Service</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>B</td>
<td>Event resulting in the loss of a single element.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Generator</td>
<td>Yes</td>
<td>No a</td>
</tr>
<tr>
<td></td>
<td>2. Transmission Circuit</td>
<td>Yes</td>
<td>No a</td>
</tr>
<tr>
<td></td>
<td>3. Transformer</td>
<td>Yes</td>
<td>No a</td>
</tr>
<tr>
<td></td>
<td>Loss of an Element without a Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Normal Clearing e:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4. Single Pole (dc) Line</td>
<td>Yes</td>
<td>No b</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Delayed Clearing e (stuck breaker or protection system failure):</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>6. Generator</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>Bipolar Block, with Normal Clearing e:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing e:</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>5. Any two circuits of a multiple circuit towerline e</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Delayed Clearing e (stuck breaker or protection system failure):</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>6. Generator</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>7. Transformer</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>8. Transmission Circuit</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
<tr>
<td></td>
<td>9. Bus Section</td>
<td>Yes</td>
<td>Planned/ Controlled d</td>
</tr>
</tbody>
</table>

*a* System Stable and both Thermal and Voltage Limits within Applicable Rating e

*b* Planned/ Controlled d
<table>
<thead>
<tr>
<th>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>3Ø Fault, with Delayed Clearing</strong> (stuck breaker or protection system failure):</td>
</tr>
<tr>
<td><strong>3Ø Fault, with Normal Clearing</strong>:</td>
</tr>
<tr>
<td>5. Breaker (failure or internal Fault)</td>
</tr>
<tr>
<td>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.</td>
</tr>
</tbody>
</table>

Evaluate for risks and consequences.
- 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.

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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 Following Loss of a Single Bulk Electric System Element (Category B)

2. Number: TPL-002-0

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: 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 the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be 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 B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.
R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

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: 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

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
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</tr>
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<tr>
<td>0</td>
<td>April 1, 2005</td>
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Table I. Transmission System Standards — Normal and Emergency Conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>System Limits or Impacts</th>
<th>Cascading Outages</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Initiating Event(s) and Contingency Element(s)</td>
<td>System Stable and both Thermal and Voltage Limits within Applicable Rating</td>
<td>Loss of Demand or Curtailed Firm Transfers</td>
</tr>
<tr>
<td>A</td>
<td>No Contingencies</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>B</td>
<td>Event resulting in the loss of a single element.</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>C</td>
<td>Event(s) resulting in the loss of two or more (multiple) elements.</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
</tbody>
</table>

**A** No Contingencies

- All Facilities in Service

**B** Event resulting in the loss of a single element.

- Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:
  - 1. Generator
  - 2. Transmission Circuit
  - 3. Transformer
- Loss of an Element without a Fault.

- Single Pole Block, Normal Clearing:
  - 4. Single Pole (dc) Line

**C** Event(s) resulting in the loss of two or more (multiple) elements.

- SLG Fault, with Normal Clearing:
  - 1. Bus Section
  - 2. Breaker (failure or internal Fault)

- SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing:
  - 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency

- Bipolar Block, with Normal Clearing:
  - 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing:
  - 5. Any two circuits of a multiple circuit towerline

- SLG Fault, with Delayed Clearing (stuck breaker or protection system failure):
  - 6. Generator
  - 7. Transformer
  - 8. Transmission Circuit
  - 9. Bus Section
**D**

Extreme event resulting in two or more (multiple) elements removed or Cascading out of service

<table>
<thead>
<tr>
<th>Fault, with Delayed Clearing(^c) (stuck breaker or protection system failure):</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Generator</td>
</tr>
<tr>
<td>2. Transmission Circuit</td>
</tr>
<tr>
<td>3. Transformer</td>
</tr>
<tr>
<td>4. Bus Section</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fault, with Normal Clearing(^d);</th>
</tr>
</thead>
<tbody>
<tr>
<td>5. Breaker (failure or internal Fault)</td>
</tr>
<tr>
<td>6. Loss of towerline with three or more circuits</td>
</tr>
<tr>
<td>7. All transmission lines on a common right-of-way</td>
</tr>
<tr>
<td>8. Loss of a substation (one voltage level plus transformers)</td>
</tr>
<tr>
<td>9. Loss of a switching station (one voltage level plus transformers)</td>
</tr>
<tr>
<td>10. Loss of all generating units at a station</td>
</tr>
<tr>
<td>11. Loss of a large Load or major Load center</td>
</tr>
<tr>
<td>12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required</td>
</tr>
<tr>
<td>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</td>
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<tr>
<td>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
</tr>
</tbody>
</table>

Evaluate for risks and consequences:

- 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.

---

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 Following Loss of a Single Bulk Electric System Element (Category B)
2. Number: TPL-002-0a
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

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 the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be 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 B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

   R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

   R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

   R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

   R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

   R1.3.5. Have all projected firm transfers modeled.

   R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.
R1.3.7. Demonstrate that system performance meets Category B contingencies.
R1.3.8. Include existing and planned facilities.
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
R1.3.11. Include the effects of existing and planned control devices.
R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
  R2.1.1. Including a schedule for implementation.
  R2.1.2. Including a discussion of expected required in-service dates of facilities.
  R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

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: 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

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<td>0</td>
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<tr>
<td>0a</td>
<td>October 23, 2008</td>
<td>Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO</td>
<td>Revised</td>
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<td>All Facilities in Service</td>
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<td>B</td>
<td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>Loss of an Element without a Fault.</td>
<td>Yes</td>
</tr>
<tr>
<td>C</td>
<td>Single Pole Block, Normal Clearing: 1. Single Pole (dc) Line</td>
<td>Yes</td>
</tr>
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<td></td>
<td>SLG Fault, with Normal Clearing: 1. Bus Section 2. Breaker (failure or internal Fault)</td>
<td>Yes</td>
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<td>SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td>
<td>Yes</td>
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<td></td>
<td>Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing: 5. Any two circuits of a multiple circuit towerline</td>
<td>Yes</td>
</tr>
<tr>
<td>D&lt;sup&gt;d&lt;/sup&gt;</td>
<td>3Ø Fault, with Delayed Clearing&lt;sup&gt;e&lt;/sup&gt; (stuck breaker or protection system failure):</td>
<td></td>
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<td>---</td>
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<td></td>
</tr>
<tr>
<td>1. Generator</td>
<td>3. Transformer</td>
<td></td>
</tr>
<tr>
<td>2. Transmission Circuit</td>
<td>4. Bus Section</td>
<td></td>
</tr>
<tr>
<td>3Ø Fault, with Normal Clearing&lt;sup&gt;f&lt;/sup&gt;,</td>
<td>5. Breaker (failure or internal Fault)</td>
<td></td>
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<tr>
<td>6. Loss of towerline with three or more circuits</td>
<td>7. All transmission lines on a common right-of-way</td>
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<td>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
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</table>

Evaluate for risks and consequences.

- 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.

---

**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.
Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

<table>
<thead>
<tr>
<th>TPL-002-0:</th>
</tr>
</thead>
<tbody>
<tr>
<td>[To be valid, the Planning Authority and Transmission Planner assessments shall:]</td>
</tr>
<tr>
<td><strong>R1.3</strong> Be supported by a current or past study and/or system simulation testing that addresses each</td>
</tr>
<tr>
<td>of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific</td>
</tr>
<tr>
<td>elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable</td>
</tr>
<tr>
<td>to the associated Regional Reliability Organization(s).</td>
</tr>
<tr>
<td><strong>R1.3.2</strong> Cover critical system conditions and study years as deemed appropriate by the responsible entity.</td>
</tr>
<tr>
<td><strong>R1.3.12</strong> Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems</td>
</tr>
<tr>
<td>or their components) at those demand levels for which planned (including maintenance) outages are performed.</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>TPL-003-0:</th>
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<tbody>
<tr>
<td>[To be valid, the Planning Authority and Transmission Planner assessments shall:]</td>
</tr>
<tr>
<td><strong>R1.3</strong> Be supported by a current or past study and/or system simulation testing that addresses each</td>
</tr>
<tr>
<td>of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific</td>
</tr>
<tr>
<td>elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable</td>
</tr>
<tr>
<td>to the associated Regional Reliability Organization(s).</td>
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<tr>
<td><strong>R1.3.2</strong> Cover critical system conditions and study years as deemed appropriate by the responsible entity.</td>
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<td><strong>R1.3.12</strong> Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems</td>
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<td>or their components) at those demand levels for which planned (including maintenance) outages are performed.</td>
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</tbody>
</table>

**Requirement R1.3.2**

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2

Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*
Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.
Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:
Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:
MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards.
A. Introduction

1. Title: System Performance Following Loss of a Single Bulk Electric System Element (Category B)

2. Number: TPL-002-0b

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 the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be 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 B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.
R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.
1.2. Compliance Monitoring Period and Reset Timeframe
   Annually.

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: 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

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<td>0a</td>
<td>October 23, 2008</td>
<td>Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO</td>
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<td>0b</td>
<td>November 5, 2009</td>
<td>Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009</td>
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### Table I. Transmission System Standards — Normal and Emergency Conditions

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<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>System Limits or Impacts</th>
</tr>
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<tr>
<td></td>
<td>Initiating Event(s) and Contingency Element(s)</td>
<td>System Stable and both Thermal and Voltage Limits within Applicable Rating&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>A</td>
<td>All Facilities in Service</td>
<td>Yes</td>
</tr>
<tr>
<td>B</td>
<td>Event resulting in the loss of a single element.</td>
<td>Yes</td>
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<tr>
<td></td>
<td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Generator</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2. Transmission Circuit</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>3. Transformer</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>Loss of an Element without a Fault.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Single Pole Block, Normal Clearing&lt;sup&gt;c&lt;/sup&gt;:</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>4. Single Pole (dc) Line</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>Event(s) resulting in the loss of two or more (multiple) elements.</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Normal Clearing&lt;sup&gt;e&lt;/sup&gt;:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Bus Section</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2. Breaker (failure or internal Fault)</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>SLG or 3Ø Fault, with Normal Clearing&lt;sup&gt;e&lt;/sup&gt;, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing&lt;sup&gt;e&lt;/sup&gt;:</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bipolar Block, with Normal Clearing&lt;sup&gt;e&lt;/sup&gt;:</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing&lt;sup&gt;e&lt;/sup&gt;:</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>5. Any two circuits of a multiple circuit towerline&lt;sup&gt;f&lt;/sup&gt;</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Delayed Clearing&lt;sup&gt;e&lt;/sup&gt; (stuck breaker or protection system failure):</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>6. Generator</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>7. Transformer</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>8. Transmission Circuit</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>9. Bus Section</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>D</strong>&lt;sup&gt;d&lt;/sup&gt;</td>
<td><strong>30 Fault, with Delayed Clearing</strong>&lt;sup&gt;e&lt;/sup&gt; (stuck breaker or protection system failure):</td>
<td></td>
</tr>
<tr>
<td>----------------</td>
<td>------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
</tbody>
</table>
| Extreme event resulting in two or more (multiple) elements removed or Cascading out of service | 1. Generator  
2. Transmission Circuit  
3. Transformer  
4. Bus Section  
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. |
| Evaluate for risks and consequences. |
| • 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. |

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.
Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**
[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**TPL-003-0:**
[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**Requirement R1.3.2**

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2

Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*
Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2

Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.
Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12

Received from Ameren on July 25, 2007:
Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12

Received from MISO on August 9, 2007:
MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards.
Appendix 2

<table>
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<th>Requirement Number and Text of Requirement</th>
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<tr>
<td><strong>R1.3.</strong> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <strong>Category B of Table 1</strong> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</td>
</tr>
<tr>
<td><strong>R1.3.10.</strong> Include the effects of existing and planned protection systems, including any backup or redundant systems.</td>
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</table>

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”
2. “…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”
3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”

**Category B of Table 1 (single Contingencies) specifies:**

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing:

4. Single Pole (dc) Line

**Note e specifies:**

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.

The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk
Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.
A. Introduction

1. Title: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. Number: TPL-003-0
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: 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 systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be 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 C of Table I (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
      R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
      R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
      R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
      R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
R1.3.5. Have all projected firm transfers modeled.
R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.
R1.3.8. Include existing and planned facilities.
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
R1.3.11. Include the effects of existing and planned control devices.
R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.
R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
R2.1.1. Including a schedule for implementation.
R2.1.2. Including a discussion of expected required in-service dates of facilities.
R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.
D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
       Compliance Monitor: Regional Reliability Organizations.
   
   1.2. Compliance Monitoring Period and Reset Timeframe
       Annually.
   
   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: 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.

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<td>April 1, 2005</td>
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## Table I. Transmission System Standards – Normal and Emergency Conditions

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<tr>
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<th>System Limits or Impacts</th>
<th>Cascading Outages</th>
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</thead>
<tbody>
<tr>
<td>A</td>
<td>All Facilities in Service</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>B</td>
<td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1. Generator</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>2. Transmission Circuit</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>3. Transformer</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Loss of an Element without a Fault.</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Single Pole Block, Normal Clearing:</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>4. Single Pole (dc) Line</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>C</td>
<td>SLG Fault, with Normal Clearing:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>1. Bus Section</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>2. Breaker (failure or internal Fault)</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>Bipolar Block, with Normal Clearing:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>5. Any two circuits of a multiple circuit towerline</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Delayed Clearing (stuck breaker or protection system failure):</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>6. Generator</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>7. Transformer</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>8. Transmission Circuit</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>9. Bus Section</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
</tbody>
</table>
D
d
Extreme event resulting in two or more (multiple) elements removed or Cascading out of service

| 3Ø Fault, with Delayed Clearing e (stuck breaker or protection system failure): |
| 1. Generator |
| 2. Transmission Circuit |
| 3. Transformer |
| 4. Bus Section |

3Ø Fault, with Normal Clearing e:

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.

Evaluate for risks and consequences.
- 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.

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 Following Loss of Two or More Bulk Electric System Elements (Category C)

2. Number: TPL-003-0a

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: 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 systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be 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 C of Table I (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.
R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.
D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

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: 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

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<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
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<td>0</td>
<td>April 1, 2005</td>
<td>Add parenthesis to item “e” on page 8.</td>
<td>Errata</td>
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<tr>
<td>0a</td>
<td>October 23, 2008</td>
<td>Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO</td>
<td>Revised</td>
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### Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Contingencies</th>
<th>System Limits or Impacts</th>
<th>Cascading Outages</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>System Stable and both Thermal and Voltage Limits within Applicable Rating</td>
<td>Loss of Demand or Curtailed Firm Transfers</td>
</tr>
<tr>
<td>A</td>
<td>All Facilities in Service</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>B</td>
<td>Event resulting in the loss of a single element.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Generator</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>2. Transmission Circuit</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>3. Transformer</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>C</td>
<td>Event(s) resulting in the loss of two or more (multiple) elements.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Normal Clearing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Bus Section</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>2. Breaker (failure or internal Fault)</td>
<td>Yes</td>
<td>Planned/Controlled</td>
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<td></td>
<td>SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>Bipolar Block, with Normal Clearing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>5. Any two circuits of a multiple circuit towerline:</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>SLG Fault, with Delayed Clearing (stuck breaker or protection system failure):</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>6. Generator</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>7. Transformer</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>8. Transmission Circuit</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
<tr>
<td></td>
<td>9. Bus Section</td>
<td>Yes</td>
<td>Planned/Controlled</td>
</tr>
</tbody>
</table>
**Standard TPL-003-0a — System Performance Following Loss of Two or More BES Elements**

<table>
<thead>
<tr>
<th>Category D</th>
<th>Description</th>
<th>Example Events</th>
</tr>
</thead>
</table>
| 3Ø Fault, with Delayed Clearing \(^e\) (stuck breaker or protection system failure): | | 1. Generator  
2. Transmission Circuit |
| 3Ø Fault, with Normal Clearing \(^e\): | | 5. Breaker (failure or internal fault) |
| 6. Loss of towerline with three or more circuits | | 6. Loss of towerline with three or more circuits |
| 7. All transmission lines on a common right-of-way | | 7. All transmission lines on a common right-of-way |
| 8. Loss of a substation (one voltage level plus transformers) | | 8. Loss of a substation (one voltage level plus transformers) |
| 9. Loss of a switching station (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 | | 10. Loss of all generating units at a station |
| 11. Loss of a large Load or major Load center | | 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 | | 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 | | 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 |

---

**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.
Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2

Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.
Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.
Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:
Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:
MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards.
A. Introduction
1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. Number: TPL-004-0
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: 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 evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:
   R1.1. Be made annually.
   R1.2. Be conducted for near-term (years one through five).
   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 D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
      R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
      R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
      R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
      R1.3.4. Have all projected firm transfers modeled.
      R1.3.5. Include existing and planned facilities.
      R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities’ respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

    Compliance Monitor: Regional Reliability Organization.

    Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

    Annually.

1.3. Data Retention

    None specified.

1.4. Additional Compliance Information

    None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.
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<th>Date</th>
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<td>0</td>
<td>April 1, 2005</td>
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</table>
### Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<thead>
<tr>
<th>Category</th>
<th>Initiating Event(s) and Contingency Element(s)</th>
<th>System Stable and both Thermal and Voltage Limits within Applicable Rating</th>
<th>Loss of Demand or Curtailed Firm Transfers</th>
<th>Cascading Outages</th>
</tr>
</thead>
<tbody>
<tr>
<td>A No Contingencies</td>
<td>All Facilities in Service</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>B Event resulting in the loss of a single element.</td>
<td>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.</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Single Pole Block, Normal Clearing: 4. Single Pole (dc) Line</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>C Event(s) resulting in the loss of two or more (multiple) elements.</td>
<td>SLG Fault, with Normal Clearing: 1. Bus Section 2. Breaker (failure or internal Fault)</td>
<td>Yes</td>
<td>Planned/Controlled</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td>
<td>Yes</td>
<td>Planned/Controlled</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing: 5. Any two circuits of a multiple circuit towerline</td>
<td>Yes</td>
<td>Planned/Controlled</td>
<td>No</td>
</tr>
</tbody>
</table>
### D

<table>
<thead>
<tr>
<th>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure):</td>
</tr>
<tr>
<td>1. Generator</td>
</tr>
<tr>
<td>2. Transmission Circuit</td>
</tr>
<tr>
<td>3. Transformer</td>
</tr>
<tr>
<td>4. Bus Section</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>3Ø Fault, with Normal Clearing:</th>
</tr>
</thead>
<tbody>
<tr>
<td>5. Breaker (failure or internal Fault)</td>
</tr>
</tbody>
</table>

| 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. |

Evaluate for risks and consequences.

- 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.

---

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: Regional and Interregional Self-Assessment Reliability Reports
2. Number: TPL-005-0
3. Purpose: To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:
   R1.1. Current year:
      R1.1.1. Winter.
      R1.1.2. Summer.
      R1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization.
   R1.2. Near-term planning horizons (years one through five). Detailed assessments shall be conducted.
   R1.3. Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns.
   R1.4. Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.

R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis.

R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:
   R3.2. Operational assessments.
   R3.3. Evaluations of emergency response preparedness.
   R3.4. Adequacy of fuel supply and hydro conditions.
   R3.5. Reliability impacts of new or proposed environmental rules and regulations.
R3.6. Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.

C. Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that annual Regional and Inter-Regional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regional Reliability Organizations or NERC.

D. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
        Compliance Monitor: NERC.
   1.2. Compliance Monitoring Period and Reset Timeframe
        Annually.
   1.3. Data Retention
        None specified.
   1.4. Additional Compliance Information
        None.

2. Levels of Non-Compliance
   2.1. Level 1: Regional, Inter-Regional, and/or special reliability assessments were provided as requested, but were incomplete.
   2.2. Level 2: Not applicable.
   2.3. Level 3: Not applicable.
   2.4. Level 4: Regional, Inter-Regional, and/or special reliability assessments were not provided.

E. Regional Differences

1. None identified.

Version History

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</table>
A. Introduction

1. Title: Data From the Regional Reliability Organization Needed to Assess Reliability
2. Number: TPL-006-0.1
3. Purpose: To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. Applicability:
   4.1. Regional Reliability Organization
5. Effective Date: April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria.

The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

R1.1. Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)
R1.2. Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)
R1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)
R1.4. Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)
R1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)
R1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)
R1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)
Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
        Compliance Monitor: NERC.
   1.2. Compliance Monitoring Period and Reset Timeframe
        Annually.
   1.3. Data Retention
        None specified.
   1.4. Additional Compliance Information
        None.

2. Levels of Non-Compliance
   2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.
   2.2. Level 2: Not applicable.
   2.3. Level 3: Not applicable.
   2.4. Level 4: Requested Regional system data, reports, or system performance information were not provided.

D. Regional Differences

1. None identified.

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<td>0.1</td>
<td>April 15, 2009</td>
<td>Corrected formatting for M1.</td>
<td>Errata</td>
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A. Introduction

1. **Title:** Data From the Regional Reliability Organization Needed to Assess Reliability
2. **Number:** TPL-006-0
3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. **Applicability:**
   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria.

The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

- **R1.1.** Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)
- **R1.2.** Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)
- **R1.3.** Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)
- **R1.4.** Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)
- **R1.5.** Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)
- **R1.6.** System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)
- **R1.7.** Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)
Measures

M2. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process
   1.1. Compliance Monitoring Responsibility
   Compliance Monitor: NERC.
   1.2. Compliance Monitoring Period and Reset Timeframe
   Annually.
   1.3. Data Retention
   None specified.
   1.4. Additional Compliance Information
   None.

2. Levels of Non-Compliance
   2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.
   2.2. Level 2: Not applicable.
   2.3. Level 3: Not applicable.
   2.4. Level 4: Requested Regional system data, reports, or system performance information were not provided.

D. Regional Differences

1. None identified.

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<td>New</td>
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</table>
A. Introduction

1. Title: Voltage and Reactive Control
2. Number: VAR-001-1
3. Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. Applicability:
   4.1. Transmission Operators.
   4.2. Purchasing-Selling Entities.
5. Effective Date: Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator’s share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.
   R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
   R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule \(^1\) at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.
   R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

---

\(^1\) The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.
R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area — including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding — to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information
The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

2.1. **Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. **Level 2:** There shall be a level two non-compliance if either of the following conditions exists:

   2.2.1 No evidence to show that directives were issued in accordance with R6.1.

   2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with R11.

2.3. **Level 3:** There shall be a level three non-compliance if either of the following conditions exists:

   2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. **Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. **Regional Differences**

None identified.

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<tr>
<td>1</td>
<td>August 2, 2006</td>
<td>BOT Adoption</td>
<td>Revised</td>
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<tr>
<td>1</td>
<td>July 3, 2007</td>
<td>Added “Generator Owners” and “Generator Operators” to Applicability section.</td>
<td>Errata</td>
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<td>August 23, 2007</td>
<td>Removed “Generator Owners” and “Generator Operators” to Applicability section.</td>
<td>Errata</td>
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</table>
A. Introduction

1. Title: Generator Operation for Maintaining Network Voltage Schedules

2. Number: VAR-002-1

3. Purpose: To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. Applicability

4.1. Generator Operator.

4.2. Generator Owner.

5. Effective Date: Six months after effective date of VAR-001-1.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings\(^1\)) as directed by the Transmission Operator.

R2.1. When a generator’s automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator’s control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

---

\(^1\) When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.
R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can’t comply with the Transmission Operator’s specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator’s directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn’t comply with the Transmission Operator’s step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process
   
   1.1. Compliance Monitoring Responsibility
       
       Regional Reliability Organization.
   
   1.2. Compliance Monitoring Period and Reset Time Frame
       
       One calendar year.
   
   1.3. Data Retention
       
       The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.
       
       The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)
       
       The Compliance Monitor shall retain any audit data for three years.
1.4. **Additional Compliance Information**

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance for Generator Operator**

2.1. **Level 1:** There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. **Level 2:** There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1, R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. **Level 3:** There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. **Level 4:** There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. **Levels of Non-Compliance for Generator Owner:**

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.
E. Regional Differences

None identified.

Version History

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<td>July 5, 2006</td>
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</tbody>
</table>
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: May 13, 2009

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings\(^1\)) as directed by the Transmission Operator.

   R2.1. When a generator’s automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

   R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

   R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

   R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator’s control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

   R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
      
      R4.1.1. Tap settings.
      
      R4.1.2. Available fixed tap ranges.

\(^1\) When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.
R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can’t comply with the Transmission Operator’s specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator’s directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn’t comply with the Transmission Operator’s step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.
1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1, R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 Level One: Not applicable.

3.1.2 Level Two: Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 Level Three: No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 Level Four: Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.
E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

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<td>1a</td>
<td>January 16, 2007</td>
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<td>May 13, 2009</td>
<td>FERC Approved – Updated Effective Date and Footer</td>
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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 rational 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 rational 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?
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-002-1.1b
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 Ratings\(^1\)) as directed by the Transmission Operator.

   R2.1. When a generator’s automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

   R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

   R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

   R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator’s control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

   R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

      R4.1.1. Tap settings.
      R4.1.2. Available fixed tap ranges.

---

\(^1\) When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.
R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can’t comply with the Transmission Operator’s specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator’s directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn’t comply with the Transmission Operator’s step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.
1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1, R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 Level One: Not applicable.

3.1.2 Level Two: Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 Level Three: No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 Level Four: Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.
E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

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<td>1.1b</td>
<td>March 3, 2009</td>
<td>Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009</td>
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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 rational 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 rational 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?
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.
Appendix 2

Interpretation of VAR-002-1a

Request:
VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator’s provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard’s requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren’t physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.
WECC Standard VAR-002-WECC-1 – Automatic Voltage Regulators

Standard Development Roadmap
This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 26, 2007</td>
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<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 30, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 25, 2008</td>
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<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
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Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002a-1. VAR-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002a-1 was approved as a NERC reliability standard.

In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Automatic Voltage Regulators are in service to control voltage to support the transfer capability. The requirements in VAR-002-WECC-1 are to ensure that the generator provides the proper voltage support when generation and transmission outages occur.

The WECC Operating Committee approved the VAR-002-WECC-1 standard as a permanent replacement standard for VAR-STD-002a-1 on March 6, 2008. This posting of the standard is for ballot by the WECC Board of Directors. The Operating Committee recommends that the WECC Board of Directors approve VAR-002-WECC-1 as a permanent replacement standard for VAR-STD-002a-1. In addition, the Operating Committee recommends that the WECC Board of Directors submit the standard to the NERC and FERC for approval.
## Future Development Plan:

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<td>2. WECC Board ballots proposed standard</td>
<td>April 16-18, 2008</td>
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<td>3. Drafting Team to review and respond to industry comments</td>
<td>May 2008</td>
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<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
</tr>
<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

**Commercial Operation** - Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
A. Introduction

1. Title: Automatic Voltage Regulators (AVR)
2. Number: VAR-002-WECC-1
3. Purpose: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.

4. Applicability
4.1. Generator Operators
4.2. Transmission Operators that operate synchronous condensers
4.3. This VAR-002-WECC-1 Standard only applies to synchronous generators and synchronous condensers that are connected to the Bulk Electric System.

5. Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall have AVR in service and in automatic voltage control mode 98% of all operating hours for synchronous generators or synchronous condensers. Generator Operators and Transmission Operators may exclude hours for R1.1 through R1.10 to achieve the 98% requirement. [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

R1.1. The synchronous generator or synchronous condenser operates for less than five percent of all hours during any calendar quarter.
R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.
R1.3. AVR exhibits instability due to abnormal system configuration.
R1.4. Due to component failure, the AVR may be out of service up to 60 consecutive days for repair per incident.
R1.5. Due to a component failure, the AVR may be out of service up to one year provided the Generator Operator or Transmission Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.
R1.6. Due to a component failure, the AVR may be out of service up to 24 months provided the Generator Operator or Transmission Operator submits documentation identifying the need for time for excitation system replacement (replace the AVR, limiters, and controls but not necessarily the power source and power bridge) and to schedule an outage.
R1.7. The synchronous generator or synchronous condenser has not achieved Commercial Operation.
R1.8. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the AVR is unavailable for service.
R1.9. The Reliability Coordinator directs Transmission Operator to operate the synchronous condenser, and the AVR is unavailable for service.
R1.10. If AVR exhibits instability due to operation of a Load Tap Changer (LTC) transformer in the area, the Transmission Operator may authorize the Generator Operator to operate the excitation system in modes other than automatic voltage control until the system configuration changes.
WECC Standard VAR-002-WECC-1 – Automatic Voltage Regulators

R2. Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10. [Violation Risk Factor: Low] [Time Horizon: Operations Assessment]

C. Measures

M1. Generator Operators and Transmission Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator and synchronous condenser of the following:

M1.1 The actual number of hours the synchronous generator or synchronous condenser was on line.

M1.2 The actual number of hours the AVR was out of service.

M1.3 The AVR in service percentage.

M1.4 If excluding AVR out of service hours as allowed in R1.1 through R1.10, provide:

M1.4.1 The number of hours excluded, and
M1.4.2 The adjusted AVR in-service percentage.

M2. If excluding hours for R1.1 through R1.10, provide the date of the outage, the number of hours out of service, and supporting documentation for each requirement that applies.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators and Transmission Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information
WECC Standard VAR-002-WECC-1 – Automatic Voltage Regulators

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.9 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.4 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the in-service percentages, do not include the time the AVR is out of service due to R1.1 through R1.10.

1.4.4 The standard shall be applied on a machine-by-machine basis (a Generator Operator or Transmission Operator can be subject to a separate sanction for each non-compliant synchronous generator and synchronous condenser).

2. Violation Severity Levels for R1

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. AVR is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. AVR is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. AVR is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. AVR is in service less than 70% of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.10.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.10.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

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<th>Date</th>
<th>Action</th>
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<tr>
<td>1</td>
<td>January 1, 2008</td>
<td>Permanent Replacement Standard for VAR-STD-002a-1</td>
</tr>
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Page 6 of 7
WECC Standard VAR-501-WECC-1 – Power System Stabilizer

Standard Development Roadmap
This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

<table>
<thead>
<tr>
<th>Completed Actions</th>
<th>Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Post Draft Standard for initial industry comments</td>
<td>September 26, 2007</td>
</tr>
<tr>
<td>2. Drafting Team to review and respond to initial industry comments</td>
<td>November 30, 2007</td>
</tr>
<tr>
<td>4. Drafting Team to review and respond to industry comments</td>
<td>January 25, 2008</td>
</tr>
<tr>
<td>6. Operating Committee ballots proposed standard</td>
<td>March 6, 2008</td>
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</table>

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002b-1. VAR-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002b-1 was approved as a NERC reliability standard.

In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Power System Stabilizers are in service to enhance system damping. The requirements in VAR-501-WECC-1 are to ensure that the generator provides the proper damping to maintain system stability when generation and transmission outages occur.

The WECC Operating Committee approved the VAR-501-WECC-1 standard as a permanent replacement standard for VAR-STD-002b-1 on March 6, 2008. This posting of the standard is for ballot by the WECC Board of Directors. The Operating Committee recommends that the WECC Board of Directors approve VAR-501-WECC-1 as a permanent replacement standard for VAR-STD-002b-1. In addition, the Operating Committee recommends that the WECC Board of Directors submit the standard to the NERC and FERC for approval.
Future Development Plan:

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<tr>
<td>2. WECC Board ballots proposed standard</td>
<td>April 16-18, 2008</td>
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<tr>
<td>3. Drafting Team to review and respond to industry comments</td>
<td>May 2008</td>
</tr>
<tr>
<td>4. NERC Board approval request</td>
<td>May 2008</td>
</tr>
<tr>
<td>5. Request FERC approval</td>
<td>June 2008</td>
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</table>
Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

Commercial Operation - Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
WECC Standard VAR-501-WECC-1 – Power System Stabilizer

A. Introduction

1. Title: Power System Stabilizer (PSS)
2. Number: VAR-501-WECC-1
3. Purpose: To ensure that Power System Stabilizers (PSS) on synchronous generators shall be kept in service.

4. Applicability
   4.1. Generator Operators

5. Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS. Generator Operators may exclude hours for R1.1 through R1.12 to achieve the 98% requirement. [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

   R1.1. The synchronous generator operates for less than five percent of all hours during any calendar quarter.
   R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.
   R1.3. PSS exhibits instability due to abnormal system configuration.
   R1.4. Unit is operating in the synchronous condenser mode (very near zero real power level).
   R1.5. Unit is generating less power than its design limit for effective PSS operation.
   R1.6. Unit is passing through a range of output that is a known “rough zone” (range in which a hydro unit is experiencing excessive vibration).
   R1.7. The generator AVR is not in service.
   R1.8. Due to component failure, the PSS may be out of service up to 60 consecutive days for repair per incident.
   R1.9. Due to a component failure, the PSS may be out of service up to one year provided the Generator Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.
   R1.10. Due to a component failure, the PSS may be out of service up to 24 months provided the Generator Operator submits documentation identifying the need for time for PSS replacement and to schedule an outage.
   R1.11. The synchronous generator has not achieved Commercial Operation.
   R1.12. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the PSS is unavailable for service.

R2. Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12. [Violation Risk Factor: Low] [Time Horizon: Operations Assessment]

C. Measures

M1. Generators Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator of the following:
WECC Standard VAR-501-WECC-1 – Power System Stabilizer

M1.1 The number of hours the synchronous generator was on line.

M1.2 The number of hours the PSS was out of service with generator on line.

M1.3 The PSS in service percentage

M1.4 If excluding PSS out of service hours as allowed in R1.1 through R1.12, provide:

- M1.4.1 The number of hours excluded, and
- M1.4.2 The adjusted PSS in-service percentage.

M2. If excluding hours for R1.1 through R1.12, provide:

- M2.1 The date of the outage
- M2.2 Supporting documentation for each requirement that applies

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.12 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.8 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.
1.4.3 When calculating the adjusted in-service percentage, the PSS out of service hours do not include the time associated with R1.1 through R1.12.

1.4.4 The standard shall be applied on a generating unit by generating unit basis (a Generator Operator can be subject to a separate sanction for each non-compliant synchronous generating unit or to a single sanction for multiple machines that operate as one unit).

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. PSS is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. PSS is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. PSS is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. PSS is in service less than 70% of all hours during which the synchronous generating unit is on line for each calendar quarter.

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.12.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.12.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

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<thead>
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<tr>
<td>1</td>
<td>January 1, 2008</td>
<td>Permanent Replacement Standard for VAR-STD-002b-1</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Automatic Voltage Regulators (AVR)

2. Number: VAR-STD-002a-1

3. Purpose: Regional Reliability Standard to ensure that automatic voltage control equipment on synchronous generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, with outages coordinated to minimize the number out of service at any one time. All synchronous generators with automatic voltage control equipment shall normally be operated in voltage control mode and set to respond effectively to voltage deviations. (Source: WECC Criterion)

4. Applicability

4.1. The requirements of this criterion apply to all Generator Operators of synchronous generating units equipped with Automatic Voltage Regulators (AVR) within the Western Interconnection. The criterion shall be applied after a synchronous generator has achieved commercial operation. The criterion shall be applied on a generator-by-generator basis (a Responsible Entity can be subject to a separate sanction for each non-compliant synchronous generator). This criterion shall not be applicable to any synchronous generator for any calendar quarter in which such synchronous generator is in service for less than five percent of all hours in such quarter (the owners of the synchronous generator shall still be subject to the data reporting requirements for such quarter). (Source: Participants Subject to Criterion)

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1. Automatic voltage control equipment on synchronous generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, with outages coordinated to minimize the number out of service at any one time. All synchronous generators with automatic voltage control equipment shall normally be operated in voltage control mode and set to respond effectively to voltage deviations. (Source: WECC Criterion)

C. Measures

WM1.

Each synchronous generating unit equipped with AVR shall have the AVR in service when the unit is on line with the following exceptions:

a) Maintenance and testing, maximum of seven calendar days per quarter.

b) AVR exhibits instability due to nonstandard transmission line configuration.

c) AVR does not operate properly due to a failed component in the AVR or resulting from a change in adjacent equipment, whether it is control oriented or physical equipment that defines system response. If these changes are outside the control of the owner and result in an operating condition that is unsuitable for operation of an AVR, an exception shall be granted until the operating condition is once again suitable, but in no event shall the period of
operation without AVR exceed 60 days, AVR must be repaired and returned to service within 60 calendar days per incident from time of failure (Source: AVR and PSS 60 Day Exclusion). If, during this 60 day period, the decision is made to replace the excitation system, the excitation system, including AVR, must be back in service within one year of commitment to replace.

If more than 60 days are needed to repair an AVR or more than one year is needed to replace an excitation system due to the length of time needed to obtain parts, an extension will be granted upon receipt of documentation by the WECC. Such documentation shall include notice of the need for replacement or repair, the expected time required for the Entity’s procurement process, plus the manufacturer delivery time, plus 30 days for installation or if an outage is required for installation the date of the next scheduled outage, and the expected completion date of the work. The total amount of time shall not exceed one year for repair of the AVR or fifteen months for replacement of the excitation system.

Responsible Entities shall provide the WECC such documentation as soon as practicable, but no later than the deadline for responding to the initial non-compliance notification letter issued by the WECC. Once repairs are complete, the WECC shall be notified with the next quarterly report of the time the AVR is back in service. (Source: Compliance Standard)

D. Compliance

1. Compliance Monitoring Process

   1.1 Compliance Monitoring Responsibility

   Western Electricity Coordinating Council (WECC)

   1.2 Compliance Monitoring Period

   Quarterly

   On or before the twentieth day of the month following the end of a quarter (or such other date specified in Form A.5), a Responsible Entity shall submit to the WECC Staff Automatic Voltage Regulator data in Form A.5 (available on the WECC web site) for the immediately preceding quarter. (Source: Data Reporting Requirement)

   1.3 Data Retention

   Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

   1.4. Additional Compliance Information

   The “Sanction Measure” is Synchronous Generating Unit Capability in MVA - and the Specified Period is the most recent calendar quarter. The sanctions shall be assessed on a quarterly basis, but for purposes of determining the applicable column in the Sanction Table, all occurrences within the specified period of the most recent calendar quarter and all immediately preceding consecutive calendar

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1 To qualify for excitation system replacement, the AVR, limiters and controls must be replaced. The power source and power bridge do not need to be replaced to qualify.
quarters in which at least one instance of non-compliance occurred shall be considered. (Source: Sanctions)

2. Levels of Non-Compliance

Sanction Measure: Synchronous Generating Unit Capability in MVA

For levels of noncompliance with a specific number of days associated, (e.g., 7 days for maintenance and testing, etc.) the level of noncompliance will be calculated by the maximum number of contiguous calendar days of non-compliance reached for that incident during the calendar quarter. If an incident continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. When an incident continues from one quarter to another it will be considered a higher level of non-compliance, not a repeat occurrence. (Source: Sanctions)

When calculating the in-service percentages in the following levels, do not include the time the AVR is out of service due to the exceptions listed above (Section C Measures).

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1. AVR is in service less than 98% but at least 96% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.1.2. AVR is out of service more than 7 calendar days but not more than 14 calendar days due to maintenance or testing, or

2.1.3. AVR is out of service for more than 60 calendar days but not more than 90 calendar days due to failed component, or

2.1.4. Following the granting of an extension for repairs, the AVR was returned to service greater than zero days but less than or equal to 30 days beyond the specified extension repair completion date.

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1. AVR is in service less than 96% but at least 94% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.2.2. AVR is out of service for more than 90 calendar days but not more than 120 calendar days due to failed component, or

2.2.3. Following the granting of an extension for repairs, the AVR was returned to service greater than 30 days but less than or equal to 60 days beyond the specified extension repair completion date.

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1. AVR is in service less than 94% but at least 92% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.3.2. AVR is out of service for more than 120 calendar days but not more than 150 calendar days due to failed component, or

2.3.3. Following the granting of an extension for repairs, the AVR was returned to service greater than 60 days but less than or equal to 90 days beyond the specified extension repair completion date.
2.4. **Level 4:** There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1. AVR is in service less than 92% of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.4.2. AVR is out of service more than 14 calendar days due to maintenance or testing, or

2.4.3. AVR is out of service for more than 150 calendar days due to failed component, or

2.4.4. Following the granting of an extension for repairs the AVR was not returned to service or was returned to service greater than 90 days beyond the specified extension repair completion date, or

2.4.5. Following the granting of an extension for replacement of the excitation system, the AVR is not in service after the specified extension replacement completion date.

**E. Regional Differences**

**Version History – Shows Approval History and Summary of Changes in the Action Field**

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<tr>
<td>1</td>
<td>November 27, 2006</td>
<td>Remove “7 calendar days but not more than” from Section 2.4.2</td>
<td>Errata</td>
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References:
NERC Standard VAR-002-1 requires the Generator Operator to 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. However, there are no measures associated with this requirement. WECC believes that the requirement for generating units to be operated with AVR in automatic voltage control mode is essential to the reliability of the Western Connection.

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2 References are provided for informational purposes only and are not a component of VAR-STD-002-1
Sanction Table

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

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<th>Level of Non-compliance</th>
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<tr>
<td>Level 1</td>
<td>Letter (A)</td>
<td>Letter (B)</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
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<tr>
<td>Level 2</td>
<td>Letter (B)</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
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<td>Level 3</td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
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<td>Level 4</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
<td>Higher of $6,000 or $6 per MW of Sanction Measure</td>
<td>Higher of $10,000 or $10 per MW of Sanction Measure</td>
</tr>
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</table>

Letter (A): Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

Letter (B): Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and

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3 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.

DEFINITIONS
Unless the context requires otherwise, all capitalized terms shall have the meanings as set out below:

Generating Unit Capability means the MVA nameplate rating of a generator.

Disturbance means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

Extraordinary Contingency shall have the meaning set out in Excuse of Performance, section B.4.c.

EXCUSE OF PERFORMANCE

A. Excused Non-Compliance

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed in below.

B. Specific Excuses

1. Governmental Order

The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if
the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. **Order of Reliability Coordinator**

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Participant in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

   Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

   a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary Contingency actually
and reasonably prevented the Reliability Entity from complying with any applicable reliability criteria; and provided further that Reliability Entity took all reasonable efforts in a timely manner to mitigate the effects of the Extraordinary Contingency and to resume full compliance with all applicable reliability criteria contained in this Standard. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Participant demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable. Reasonable efforts shall not include the settlement of any strike, lockout or labor dispute.

b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

5. Participation in Field Testing

Any action taken or not taken by the Reliability Entity in conjunction with the Reliability Entity’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Reliability Entity’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Reliability Entity’s non-
compliance is the result of Reliability Entity’s reasonable efforts to participate in the field testing.
AVR and PSS 60 Day Exclusion

The Procedure for requesting the sixty consecutive day PSS and/or AVR exclusion is as follows:

a. Submit, by email, a notification request to rms@wecc.biz as soon as practicable but no later than the deadline for responding to the initial noncompliance notification letter when the AVR and/or PSS was removed for repair. The notification request should contain the following:
   i. The name of the organization making the request (use the WECC four letter acronym when available).
   ii. The name of the generating unit being repaired (same as on reporting form).
   iii. The date and time AVR and/or PSS was removed for repair.
   iv. Identify the equipment to be repaired (AVR and/or PSS).
   v. The schedule for completion of repairs.

b. Submit the notification by email to rms@wecc.biz stating that AVR and/or PSS repairs have been completed by the twentieth of the month following the quarter when repairs were completed. The email should be part of the AVR and PSS reporting process, and should contain the following:
   i. The name of the organization reporting (use the WECC four letter acronym when available).
   ii. The name of the generating unit that was repaired (same as on reporting form).
   iii. Identify the equipment that was repaired.
   iv. The date and time the equipment was removed from service for repair.
   v. The date and time the equipment was placed back in service after being repaired.
   vi. The number of hours the unit operated without AVR and/or PSS under the sixty consecutive day exclusion.

AVR and PSS data submission by the reporting entity should report all hours that AVR and/or PSS were noncompliant, including the exclusion request. The WECC staff will adjust the noncompliant hours report on the AVR and PSS reporting forms to reflect the sixty day exclusion.
A. Introduction

1. Title: Power System Stabilizer (PSS)
2. Number: VAR-STD-002b-1
3. Purpose: Regional Reliability Standard to ensure that Power System Stabilizers on generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, and shall be properly tuned in accordance with WECC requirements. (Source: WECC Criterion)

4. Applicability

4.1. The requirements of this criterion apply to all Generator Operators with generators equipped with Power System Stabilizers (PSS) within the Western Interconnection. The criterion shall be applied three months after a generator has achieved commercial operation. The criterion shall be applied on a generator-by-generator basis (i.e., a Responsible Entity can be subject to a separate sanction for each non-compliant generator). This criterion shall not be applicable to any generator for any calendar quarter in which such generator is in service for less than five percent of all hours in such quarter (the owners of the generation shall still be subject to the data reporting requirements for such quarter). (Source: Participants Subject to Criterion)

5. Effective Date: This Western Electricity Coordinating Council Regional Reliability Standard will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act. This Regional Reliability Standard shall be in effect for one year from the date of Commission approval or until a North American Standard or a revised Western Electricity Coordinating Council Regional Reliability Standard goes into place, whichever occurs first. At no time shall this regional Standard be enforced in addition to a similar North American Standard.

B. Requirements

WR1. Power System Stabilizers on generators shall be kept in service at all times, unless one of the exemptions listed in Section C (Measures) applies, and shall be properly tuned in accordance with WECC requirements. (Source: WECC Criterion)

C. Measures

WM1.

Each generating unit equipped with PSS shall have the PSS in service when the unit is on line with the following exceptions:

a) Maintenance and testing, maximum of seven calendar days per quarter.

b) PSS exhibits instability due to nonstandard transmission line configuration.

c) Unit is operating in the synchronous condenser mode (very near zero real power level).

d) Unit is generating less power than its design limit for effective PSS operation.

e) Unit is passing through a range of output that is a known “rough zone” (range in which a hydro unit is experiencing excessive vibration).

f) AVR is not in service.
g) PSS does not operate properly due to a failed component in the PSS or resulting from a change in adjacent equipment whether it is control oriented or physical equipment that defines system response. If these changes are outside the control of the owner and result in an operating condition that is unsuitable for operation of PSS, an exception shall be granted until the operating condition is once again suitable, but in no event shall the period of operation without PSS exceed 60 days. The PSS must be repaired and returned to service within 60 calendar days or replaced within one year per incident from time of failure (Source: AVR and PSS 60 Day Exclusion). If, during this 60 day or one year period, the decision is made to replace the excitation system, the excitation system, including PSS, must be back in service within one year of commitment to replace.

If more than 60 days are needed to repair a PSS or more than one year is needed to replace a PSS or excitation system due to the length of time needed to obtain parts, an extension will be granted upon receipt of documentation by the WECC Staff. Such documentation shall include notice of the need for replacement or repair, the expected time required for the Responsible Entity’s procurement process, plus the manufacturer delivery time, plus 30 days for installation or if an outage is required for installation the date of the next scheduled outage, and the expected completion date of the work. The total amount of time shall not exceed one year for repair of the PSS or fifteen months for replacement of the PSS or excitation system.

Participant shall provide the WECC Staff such documentation as soon as practicable, but no later than the deadline for responding to the initial non-compliance notification letter issued by the WECC Staff. Once repairs are complete, WECC Staff shall be notified with the next quarterly report of the time the PSS is back in service. (Source: Compliance Standard)

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Western Electricity Coordinating Council (WECC)

1.2 Compliance Monitoring Period

Quarterly

On or before the twentieth day of the month following the end of a quarter (or such other date specified in Form A.5), a Responsible Entity shall submit to the WECC Staff Power System Stabilizer data in Form A.5 (available on the WECC web site) for the immediately preceding quarter. (Source: Data Reporting Requirement)

1.3 Data Retention

Data will be retained in electronic form for at least one year. The retention period will be evaluated before expiration of one year to determine if a longer retention period is necessary. If the data is being reviewed to address a question of compliance, the data will be saved beyond the normal retention period until the question is formally resolved. (Source: NERC Language)

1.4 Additional Compliance Information

The “Sanction Measure” is Synchronous Generating Unit Capability in MVA - and the Specified Period is the most recent calendar quarter. The sanctions shall be assessed on a quarterly basis, but for purposes of determining the applicable
column in the Sanction Table, all occurrences within the specified period of the most recent calendar quarter and all immediately preceding consecutive calendar quarters in which at least one instance of non-compliance occurred shall be considered. (Source: Sanctions)

2. Levels of Non-Compliance

Sanction Measure: Synchronous Generating Unit Capability in MVA

For levels of noncompliance with a specific number of days associated, (e.g., 7 days for maintenance and testing, etc.) the level of noncompliance will be calculated by the maximum number of contiguous calendar days of non-compliance reached for that incident during the calendar quarter. If an incident continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. When an incident continues from one quarter to another it will be considered a higher level of non-compliance, not a repeat occurrence. (Source: Sanctions)

When calculating the in-service percentages in the following levels, do not include the time the PSS is out of service due to the exceptions listed above (Section IV.A.4. a-c).

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1. PSS is in service less than 98% but at least 96% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.1.2. PSS is out of service more than 7 calendar days but not more than 14 calendar days due to maintenance or testing, or

2.1.3. PSS is out of service for more than 60 calendar days but not more than 90 calendar days due to failed component, or

2.1.4. Following the granting of an extension for repairs, the PSS was returned to service greater than zero days but less than or equal to 30 days beyond the specified extension repair completion date.

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1. PSS is in service less than 96% but at least 94% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.2.2. PSS is out of service for more than 90 calendar days but not more than 120 calendar days due to failed component, or

2.2.3. Following the granting of an extension for repairs, the PSS was returned to service greater than 30 days but less than or equal to 60 days beyond the specified extension repair completion date.

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1. PSS is in service less than 94% but at least 92% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.3.2. PSS is out of service for more than 120 calendar days but not more than 150 calendar days due to failed component, or
2.3.3. Following the granting of an extension for repairs, the PSS was returned to service greater than 60 days but less than or equal to 90 days beyond the specified extension repair completion date.

2.4. **Level 4:** There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1. PSS is in service less than 92% of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.4.2. PSS is out of service more than 14 calendar days due to maintenance or testing, or

2.4.3. PSS is out of service for more than 150 calendar days due to failed component, or

2.4.4. Following the granting of an extension for repairs the PSS was not returned to service or was returned to service greater than 90 days beyond the specified extension repair completion date, or

2.4.5. Following the granting of an extension for replacement of the excitation system, the PSS is not in service after the specified extension replacement completion date.

**E. Regional Differences**

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>November 27, 2006</td>
<td>Remove &quot;7 calendar days but not more than&quot; from Section 2.4.2</td>
<td>Errata</td>
</tr>
</tbody>
</table>

References:

NERC Standard VAR-002-1 requires the Generator Operator to notify its associated Transmission Operator of a status or capability change of the Power System Stabilizer (PSS). However, there is no requirement for the unit to be operated with the PSS in service. WECC believes that the requirement for generating units to be operated with Power System Stabilizer is essential to the reliability of the Western Connection.
Sanction Table

Sanctions for non-compliance with respect to each criterion in Section B Requirements shall be assessed pursuant to the following table. All monetary sanctions shall also include sending of Letter (B).

<table>
<thead>
<tr>
<th>Level of Non-compliance</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4 or more</th>
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</thead>
<tbody>
<tr>
<td><strong>Level 1</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Letter (A)</td>
<td></td>
<td></td>
<td></td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
<tr>
<td>Letter (B)</td>
<td></td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
<td></td>
</tr>
<tr>
<td><strong>Level 2</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Letter (B)</td>
<td></td>
<td></td>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
<td></td>
</tr>
<tr>
<td><strong>Level 3</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Higher of $1,000 or $1 per MW of Sanction Measure</td>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
<td>Higher of $6,000 or $6 per MW of Sanction Measure</td>
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<tr>
<td><strong>Level 4</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Higher of $2,000 or $2 per MW of Sanction Measure</td>
<td>Higher of $4,000 or $4 per MW of Sanction Measure</td>
<td>Higher of $6,000 or $6 per MW of Sanction Measure</td>
<td>Higher of $10,000 or $10 per MW of Sanction Measure</td>
<td></td>
</tr>
</tbody>
</table>

**Letter (A):** Letter to Responsible Entity’s Chief Executive Officer informing the Responsible Entity of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.

**Letter (B):** Identical to Letter (A), with additional copies to (i) Chairman of the Board of Responsible Entity (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over Responsible Entity, and, in the case of U.S. entities, FERC, and Department of Energy, if such government entities request such information.

The “Specified Period” and the “Sanction Measure” are as specified in Section D1.4 for each criterion.

Sanctions shall be assessed for all instances of non-compliance within a Specified Period. For example, if a Responsible Entity had two instances of Level 1 non-compliance and

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2 Copies of Letter A and Letter B will be sent to WECC Member Representative and WECC Operating Committee Representative when the Generator Operator is a WECC member.
one instance of Level 3 non-compliance for a specific criterion in the first Specified Period, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 1 of the Level 3 row.

If the Responsible Entity fails to comply with a given criterion for two or more consecutive Specified Periods, the sanctions assessed at each level of noncompliance for the most recent Specified Period shall be the sanction specified in the column immediately to the right of the indicated sanction. For example, if a Responsible Entity fails to comply with a given criterion for two consecutive Specified Periods, and in the second Specified Period the Participant has one instance of Level 1 non-compliance and two instances of Level 3 non-compliance, it would be assessed the sanction from Column 2 of the Level 1 row, and the sanction from Column 3 of the Level 3 row. If the sanction assessed at the highest level is the sanction in Column 4, no such modification of the specified sanction shall occur.

**DEFINITIONS**

Unless the context requires otherwise, all capitalized terms shall have the meanings as set out below:

**Generating Unit Capability** means the MVA nameplate rating of a generator.

**Disturbance** means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

**Extraordinary Contingency** shall have the meaning set out in Excuse of Performance, section B.4.c.

**EXCUSE OF PERFORMANCE**

**A. Excused Non-Compliance**

Non-compliance with any of the reliability criteria contained in this Standard shall be excused and no sanction applied if such non-compliance results directly from one or more of the actions or events listed below.

**B. Specific Excuses**

1. **Governmental Order**

   The Reliability Entity’s compliance with or action under any applicable law or regulation or other legal obligation related thereto or any curtailment, order, regulation or restriction imposed by any governmental authority (other than the Reliability Entity, if
the Reliability Entity is a municipal corporation or a federal, state, or provincial governmental entity or subdivision thereof).

2. **Order of Reliability Coordinator**

   The Reliability Entity’s compliance or reasonable effort to comply with any instruction, directive, order or suggested action (“Security Order”) by the WECC Reliability Coordinator for the WECC sub-region within which the Reliability Entity is operating, provided that the need for such Security Order was not due to the Reliability Entity’s non-compliance with (a) the WECC Reliability Criteria for Transmission System Planning, (b) the WECC Power Supply Design Criteria, (c) the WECC Minimum Operating Reliability Criteria, or (d) any other WECC reliability criterion, policy or procedure then in effect (collectively, “WECC Reliability Standards”), and provided further that the Reliability Entity in complying or attempting to comply with such Security Order has taken all reasonable measures to minimize Reliability Entity’s non-compliance with the reliability criteria.

3. **Protection of Facilities**

   Any action taken or not taken by the Reliability Entity which, in the reasonable judgment of the Reliability Entity, was necessary to protect the operation, performance, integrity, reliability or stability of the Reliability Entity’s computer system, electric system (including transmission and generating facilities), or any electric system with which the Reliability Entity’s electric system is interconnected, whether such action occurs automatically or manually; provided that the need for such action or inaction was not due to Reliability Entity’s non-compliance with any WECC Reliability Standard and provided further that Reliability Entity could not have avoided the need for such action or inaction through reasonable efforts taken in a timely manner. Reasonable efforts shall include shedding load, disconnecting facilities, altering generation patterns or schedules on the transmission system, or purchasing energy or capacity, except to the extent that the Reliability Entity demonstrates to the WECC Staff and/or the RCC that in the particular circumstances such action would have been unreasonable.

4. **Extraordinary Contingency**

   a. Any Extraordinary Contingency (as defined in subsection c); provided that this provision shall apply only to the extent and for the duration that the Extraordinary
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b. Any Reliability Entity whose compliance is prevented by an Extraordinary Contingency shall immediately notify the WECC of such contingency and shall report daily or at such other interval prescribed by the WECC the efforts being undertaken to mitigate the effects of such contingency and to bring the Reliability Entity back into full compliance.

c. An Extraordinary Contingency means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).

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   ii. The name of the generating unit being repaired (same as on reporting form).
   iii. The date and time AVR and/or PSS was removed for repair.
   iv. Identify the equipment to be repaired (AVR and/or PSS).
   v. The schedule for completion of repairs.

b. Submit the notification by email to rms@wecc.biz stating that AVR and/or PSS repairs have been completed by the twentieth of the month following the quarter when repairs were completed. The email should be part of the AVR and PSS reporting process, and should contain the following:
   i. The name of the organization reporting (use the WECC four letter acronym when available).
   ii. The name of the generating unit that was repaired (same as on reporting form).
   iii. Identify the equipment that was repaired.
   iv. The date and time the equipment was removed from service for repair.
   v. The date and time the equipment was placed back in service after being repaired.
   vi. The number of hours the unit operated without AVR and/or PSS under the sixty consecutive day exclusion.

AVR and PSS data submission by the reporting entity should report all hours that AVR and/or PSS were noncompliant, including the exclusion request. The WECC staff will adjust the noncompliant hours report on the AVR and PSS reporting forms to reflect the sixty day exclusion.
Glossary of Terms Used in NERC Reliability Standards  
Updated April 20, 2010

Introduction:
This Glossary lists each term that was defined for use in one or more of NERC’s continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through February 16, 2010.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC and ReliabilityFirst are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC’s initial set of reliability standards, called the “Version 0” standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC’s Reliability Standards Development Process, and added to this glossary following board adoption, with the “FERC approved” date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following: sarcomm@nerc.com with “Glossary Comment” in the subject line.
Continent-wide Definitions:

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<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approval Date</th>
<th>FERC Approval Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adequacy [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.</td>
</tr>
<tr>
<td>Adjacent Balancing Authority [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.</td>
</tr>
<tr>
<td>Adverse Reliability Impact [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.</td>
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<tr>
<td>After the Fact [Archive]</td>
<td>ATF</td>
<td>10/29/2008</td>
<td>12/17/2009</td>
<td>A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.</td>
</tr>
<tr>
<td>Altitude Correction Factor [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.</td>
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<tr>
<td>Ancillary Service [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider’s transmission system in accordance with good utility practice. (From FERC order 888-A.)</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approval Date</td>
<td>FERC Approval Date</td>
<td>Definition</td>
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<tr>
<td>Anti-Aliasing Filter [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.</td>
</tr>
<tr>
<td>Area Control Error [Archive]</td>
<td>ACE</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The instantaneous difference between a Balancing Authority’s net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.</td>
</tr>
<tr>
<td>Area Interchange Methodology [Archive]</td>
<td></td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.</td>
</tr>
<tr>
<td>Arranged Interchange [Archive]</td>
<td></td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>The state where the Interchange Authority has received the Interchange information (initial or revised).</td>
</tr>
<tr>
<td>Automatic Generation Control [Archive]</td>
<td>AGC</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.</td>
</tr>
<tr>
<td>Available Flowgate Capability [Archive]</td>
<td>AFC</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approval Date</td>
<td>FERC Approval Date</td>
<td>Definition</td>
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<tr>
<td>Available Transfer Capability</td>
<td>ATC</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.</td>
</tr>
<tr>
<td>Available Transfer Capability</td>
<td>ATC</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.</td>
</tr>
<tr>
<td>Available Transfer Capability Implementation Document</td>
<td>ATCID</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider’s calculation of ATC or AFC.</td>
</tr>
<tr>
<td>ATC Path</td>
<td></td>
<td>08/22/2008</td>
<td>Not approved; Modification directed 11/24/09</td>
<td>Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[^1].</td>
</tr>
</tbody>
</table>

[^1]: See 18 CFR 37.6(b)(1)
<table>
<thead>
<tr>
<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balancing Authority</td>
<td>BA</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.</td>
</tr>
<tr>
<td>Balancing Authority Area</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.</td>
</tr>
<tr>
<td>Base Load</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The minimum amount of electric power delivered or required over a given period at a constant rate.</td>
</tr>
<tr>
<td>Blackstart Capability Plan</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.</td>
</tr>
<tr>
<td>Blackstart Resource</td>
<td></td>
<td>8/5/2009</td>
<td></td>
<td>A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
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</tr>
<tr>
<td>Block Dispatch</td>
<td>BOT</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable “blocks,” each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or “must-run” status).</td>
</tr>
<tr>
<td>Bulk Electric System</td>
<td>BERS</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.</td>
</tr>
<tr>
<td>Burden</td>
<td>BURD</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.</td>
</tr>
<tr>
<td>Business Practices</td>
<td>BP</td>
<td>08/22/2008</td>
<td>Not approved; Modification directed 11/24/09</td>
<td>Those business rules contained in the Transmission Service Provider’s applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
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</tr>
<tr>
<td>Capacity Benefit Margin</td>
<td>CBM</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.</td>
</tr>
<tr>
<td>Capacity Emergency</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.</td>
</tr>
<tr>
<td>Cascading</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.</td>
</tr>
</tbody>
</table>
### Glossary of Terms Used in NERC Reliability Standards

<table>
<thead>
<tr>
<th>Continent-wide Term</th>
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<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cascading Outages</td>
<td>[Archive]</td>
<td>11/1/2006 Withrawn 2/12/2008</td>
<td>FERC Remanded 12/27/2007</td>
<td>The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.</td>
</tr>
<tr>
<td>Clock Hour</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.</td>
</tr>
<tr>
<td>Confirmed Interchange</td>
<td>[Archive]</td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>The state where the Interchange Authority has verified the Arranged Interchange.</td>
</tr>
<tr>
<td>Congestion Management Report</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.</td>
</tr>
<tr>
<td>Constrained Facility</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.</td>
</tr>
<tr>
<td>Contingency</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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<td>FERC Approved Date</td>
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<tr>
<td>Contingency Reserve</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.</td>
</tr>
<tr>
<td>Control Performance Standard</td>
<td>CPS</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The reliability standard that sets the limits of a Balancing Authority’s Area Control Error over a specified time period.</td>
</tr>
<tr>
<td>Cranking Path</td>
<td></td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.</td>
</tr>
<tr>
<td>Critical Assets</td>
<td></td>
<td>5/2/2006</td>
<td>1/18/2008</td>
<td>Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.</td>
</tr>
<tr>
<td>Curtailment Threshold</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.</td>
</tr>
<tr>
<td>Cyber Assets</td>
<td></td>
<td>5/2/2006</td>
<td>1/18/2008</td>
<td>Programmable electronic devices and communication networks including hardware, software, and data.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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</tbody>
</table>
| Cyber Security Incident [Archive] |         | 5/2/2006          | 1/18/2008        | Any malicious act or suspicious event that:  
• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,  
• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset. |
<table>
<thead>
<tr>
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<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
</table>
| Demand                                  |         | 2/8/2005          | 3/16/2007          | 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.  
2. The rate at which energy is being used by the customer. |
| Demand-Side Management                   | DSM     | 2/8/2005          | 3/16/2007          | The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.                                                                 |
| Direct Control Load Management           | DCLM    | 2/8/2005          | 3/16/2007          | Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. |
| Dispatch Order                          |         | 08/22/2008        | 11/24/2009         | A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.                                  |
| Dispersed Load by Substations            |         | 2/8/2005          | 3/16/2007          | Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.                                                                                      |
| Distribution Factor                      | DF      | 2/8/2005          | 3/16/2007          | The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).                                                                          |
### Glossary of Terms Used in NERC Reliability Standards

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</tr>
</thead>
<tbody>
<tr>
<td>Distribution Provider</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.</td>
</tr>
</tbody>
</table>
2. Any perturbation to the electric system.  
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. |
| Disturbance Control Standard | DCS | 2/8/2005 | 3/16/2007 | The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range. |
| Disturbance Monitoring Equipment | DME | 8/2/2006 | 3/16/2007 | Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders²:  
- Sequence of event recorders which record equipment response to the event  
- Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.  
- Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions |

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² Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.
<table>
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<tr>
<td>Dynamic Interchange Schedule or Dynamic Schedule</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.</td>
<td></td>
</tr>
<tr>
<td>Dynamic Transfer</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.</td>
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</tr>
<tr>
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</tr>
<tr>
<td>Economic Dispatch</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The allocation of demand to individual generating units on line to effect the most economical production of electricity.</td>
</tr>
<tr>
<td>Electrical Energy</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).</td>
</tr>
<tr>
<td>Electronic Security Perimeter</td>
<td>[Archive]</td>
<td>5/2/2006</td>
<td>1/18/2008</td>
<td>The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.</td>
</tr>
<tr>
<td>Element</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.</td>
</tr>
<tr>
<td>Emergency or BES Emergency</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.</td>
</tr>
<tr>
<td>Emergency Rating</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Energy Emergency</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers’ expected energy requirements.</td>
</tr>
<tr>
<td>Equipment Rating</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.</td>
</tr>
<tr>
<td>Existing Transmission Commitments</td>
<td>ETC</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>Committed uses of a Transmission Service Provider’s Transmission system considered when determining ATC or AFC.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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<tr>
<td>Facility</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)</td>
</tr>
<tr>
<td>Facility Rating</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.</td>
</tr>
<tr>
<td>Fault</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.</td>
</tr>
<tr>
<td>Fire Risk</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The likelihood that a fire will ignite or spread in a particular geographic area.</td>
</tr>
<tr>
<td>Firm Demand</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.</td>
</tr>
<tr>
<td>Flashover</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
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</tbody>
</table>
| Flowgate            | [Archive] | 08/22/2008       | 11/24/2009         | 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.  
2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. |
| Flowgate Methodology | [Archive] | 08/22/2008       | 11/24/2009         | The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC). |
2. The condition in which the equipment is unavailable due to unanticipated failure. |
<p>| Frequency Bias      | [Archive] | 2/8/2005         | 3/16/2007          | A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area’s response to Interconnection frequency error. |</p>
<table>
<thead>
<tr>
<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency Bias Setting</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.</td>
</tr>
<tr>
<td>Frequency Error</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The difference between the actual and scheduled frequency. $(F_A - F_S)$</td>
</tr>
<tr>
<td>Frequency Regulation</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.</td>
</tr>
<tr>
<td>Frequency Response</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).</td>
</tr>
<tr>
<td>Continent-wide Term</td>
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</tr>
<tr>
<td>Generator Operator</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.</td>
</tr>
<tr>
<td>Generator Shift Factor</td>
<td>GSF</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A factor to be applied to a generator’s expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.</td>
</tr>
<tr>
<td>Generator-to-Load Distribution Factor</td>
<td>GLDF</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.</td>
</tr>
<tr>
<td>Generation Capability Import Requirement</td>
<td>GCIR</td>
<td>11/13/2008</td>
<td>11/24/2009</td>
<td>The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.</td>
</tr>
</tbody>
</table>
| Host Balancing Authority            |         | 2/8/2005          | 3/16/2007          | 1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority’s metered boundaries.  
2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located. |
<table>
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<tr>
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</thead>
<tbody>
<tr>
<td>Implemented Interchange [Archive]</td>
<td></td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.</td>
</tr>
<tr>
<td>Independent Power Producer [Archive]</td>
<td>IPP</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Any entity that owns or operates an electricity generating facility that is not included in an electric utility’s rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.</td>
</tr>
<tr>
<td>Interchange Authority [Archive]</td>
<td></td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Interchange Schedule</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.</td>
</tr>
<tr>
<td>Interchange Transaction</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.</td>
</tr>
<tr>
<td>Interconnected Operations Service</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.</td>
</tr>
<tr>
<td>Interconnection</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.</td>
</tr>
<tr>
<td>Interconnection Reliability Operating Limit</td>
<td>Archive</td>
<td>2/8/2005</td>
<td>3/16/2007 Retired 12/27/2007</td>
<td>The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.</td>
</tr>
<tr>
<td>Interconnection Reliability Operating Limit</td>
<td>Archive</td>
<td>11/1/2006</td>
<td>12/27/2007</td>
<td>A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>DOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Interconnection Reliability Operating Limit $T_v$</td>
<td>IROL $T_v$</td>
<td>11/1/2006</td>
<td>12/27/2007</td>
<td>The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit’s $T_v$ shall be less than or equal to 30 minutes.</td>
</tr>
<tr>
<td>Intermediate Balancing Authority</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.</td>
</tr>
<tr>
<td>Interruptible Load or Interruptible Demand</td>
<td></td>
<td>11/1/2006</td>
<td>3/16/2007</td>
<td>Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.</td>
</tr>
<tr>
<td>Joint Control</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Automatic Generation Control of jointly owned units by two or more Balancing Authorities.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Limiting Element</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The element that is 1.) Either operating at its appropriate rating, or 2.) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.</td>
</tr>
<tr>
<td>Load</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An end-use device or customer that receives power from the electric system.</td>
</tr>
<tr>
<td>Load Shift Factor</td>
<td>LSF</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.</td>
</tr>
<tr>
<td>Load-Serving Entity</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.</td>
</tr>
<tr>
<td>Misoperation</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>▪️ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>▪️ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>▪️ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
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</tr>
<tr>
<td>Native Load [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The end-use customers that the Load-Serving Entity is obligated to serve.</td>
</tr>
<tr>
<td>Net Actual Interchange [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.</td>
</tr>
<tr>
<td>Net Energy for Load [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.</td>
</tr>
<tr>
<td>Net Scheduled Interchange [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.</td>
</tr>
<tr>
<td>Network Integration Transmission Service [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.</td>
</tr>
<tr>
<td>Non-Firm Transmission Service [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.</td>
</tr>
<tr>
<td>Non-Spinning Reserve [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Normal Clearing</td>
<td>[Archive]</td>
<td>11/1/2006</td>
<td>12/27/2007</td>
<td>A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.</td>
</tr>
<tr>
<td>Normal Rating</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.</td>
</tr>
<tr>
<td>Nuclear Plant Generator Operator</td>
<td>[Archive]</td>
<td>5/2/2007</td>
<td>10/16/2008</td>
<td>Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.</td>
</tr>
<tr>
<td>Nuclear Plant Off-site Power Supply (Off-site Power)</td>
<td>[Archive]</td>
<td>5/2/2007</td>
<td>10/16/2008</td>
<td>The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.</td>
</tr>
<tr>
<td>Nuclear Plant Licensing Requirements (NPLRs)</td>
<td>[Archive]</td>
<td>5/2/2007</td>
<td>10/16/2008</td>
<td>Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.</td>
</tr>
<tr>
<td>Nuclear Plant Interface Requirements (NPIRs)</td>
<td>[Archive]</td>
<td>5/2/2007</td>
<td>10/16/2008</td>
<td>The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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</tr>
<tr>
<td>Off-Peak [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.</td>
</tr>
<tr>
<td>On-Peak [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.</td>
</tr>
<tr>
<td>Open Access Same Time Information Service [Archive]</td>
<td>OASIS</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.</td>
</tr>
<tr>
<td>Operating Plan [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.</td>
</tr>
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<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Operating Procedure</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.</td>
</tr>
<tr>
<td>Operating Process</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.</td>
</tr>
<tr>
<td>Operating Reserve</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.</td>
</tr>
</tbody>
</table>
  - Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or  
  - Load fully removable from the system within the Disturbance Recovery Period following the contingency event.                                                                                                                                           |
<table>
<thead>
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</thead>
<tbody>
<tr>
<td>Operating Reserve – Supplemental</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The portion of Operating Reserve consisting of:</td>
</tr>
<tr>
<td>[Archive]</td>
<td></td>
<td></td>
<td></td>
<td>• Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</td>
</tr>
<tr>
<td>Operating Voltage</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.</td>
</tr>
<tr>
<td>Operational Planning Analysis</td>
<td></td>
<td>10/17/2008</td>
<td></td>
<td>An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).</td>
</tr>
<tr>
<td>Outage Transfer Distribution Factor</td>
<td>OTDF</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).</td>
</tr>
<tr>
<td>Overlap Regulation Service</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority’s actual interchange, frequency response, and schedules into providing Balancing Authority’s AGC/ACE equation.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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</tr>
<tr>
<td>Participation Factors [Archive]</td>
<td></td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.</td>
</tr>
</tbody>
</table>
| Peak Demand [Archive]               |         | 2/8/2005          | 3/16/2007          | 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).  
2. The highest instantaneous demand within the Balancing Authority Area. |
<p>| Performance-Reset Period [Archive]  |         | 2/7/2006          | 3/16/2007          | The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.         |
| Physical Security Perimeter [Archive]|         | 5/2/2006          | 1/18/2008          | The physical, completely enclosed (&quot;six-wall&quot;) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled. |
| Planning Authority [Archive]        |         | 2/8/2005          | 3/16/2007          | The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. |
| Point of Delivery [Archive]         | POD     | 2/8/2005          | 3/16/2007          | A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy. |
| Point of Receipt [Archive]          | POR     | 2/8/2005          | 3/16/2007          | A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output. |</p>
<table>
<thead>
<tr>
<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Point to Point Transmission Service [Archive]</td>
<td>PTP</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.</td>
</tr>
<tr>
<td>Postback [Archive]</td>
<td></td>
<td>08/22/2008</td>
<td>Not approved; Modification directed 11/24/09</td>
<td>Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.</td>
</tr>
<tr>
<td>Power Transfer Distribution Factor [Archive]</td>
<td>PTDF</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.</td>
</tr>
<tr>
<td>Protection System [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/17/07</td>
<td>Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.</td>
</tr>
<tr>
<td>Pseudo-Tie [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.</td>
</tr>
<tr>
<td>Purchasing-Selling Entity [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Ramp Rate or Ramp</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.</td>
</tr>
<tr>
<td>Rated Electrical Operating Conditions</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate</td>
</tr>
<tr>
<td>Rated System Path Methodology</td>
<td></td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.</td>
</tr>
<tr>
<td>Reactive Power</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).</td>
</tr>
<tr>
<td>Real Power</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The portion of electricity that supplies energy to the load.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Reallocation</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.</td>
</tr>
<tr>
<td>Real-time</td>
<td>[Archive]</td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)</td>
</tr>
<tr>
<td>Real-time Assessment</td>
<td></td>
<td>10/17/2008</td>
<td></td>
<td>An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.</td>
</tr>
<tr>
<td>Regional Reliability Plan</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.</td>
</tr>
<tr>
<td>Regulating Reserve</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Regulation Service</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.</td>
</tr>
<tr>
<td>Reliability Coordinator</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.</td>
</tr>
<tr>
<td>Reliability Coordinator Area</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.</td>
</tr>
<tr>
<td>Reliability Coordinator Information System</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The system that Reliability Coordinators use to post messages and share operating information in real time.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Reportable Disturbance</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.</td>
</tr>
<tr>
<td>Request for Interchange</td>
<td>RFI</td>
<td>5/2/2006</td>
<td>3/16/2007</td>
<td>A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.</td>
</tr>
<tr>
<td>Reserve Sharing Group</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.</td>
</tr>
<tr>
<td>Resource Planner</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.</td>
</tr>
<tr>
<td>Response Rate</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Right-of-Way (ROW)</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.</td>
</tr>
</tbody>
</table>

[Archive]
<table>
<thead>
<tr>
<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>(Noun) An Interchange Schedule.</td>
</tr>
<tr>
<td>Scheduled Frequency</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>60.0 Hertz, except during a time correction.</td>
</tr>
<tr>
<td>Sink Balancing Authority</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)</td>
</tr>
<tr>
<td>Source Balancing Authority</td>
<td>[Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Special Protection System (Remedial Action Scheme) [Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.</td>
<td></td>
</tr>
<tr>
<td>Stability [Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.</td>
<td></td>
</tr>
<tr>
<td>Stability Limit [Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.</td>
<td></td>
</tr>
<tr>
<td>Supervisory Control and Data Acquisition [Archive]</td>
<td>SCADA</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A system of remote control and telemetry used to monitor and control the transmission system.</td>
</tr>
<tr>
<td>Supplemental Regulation Service [Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority’s ACE.</td>
<td></td>
</tr>
<tr>
<td>Surge [Archive]</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.</td>
<td></td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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</tr>
<tr>
<td>Sustained Outage</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.</td>
</tr>
</tbody>
</table>
| System Operating Limit              |         | 2/8/2005          | 3/16/2007         | The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:  
  - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)  
  - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)  
  - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)  
  - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits) |
<p>| System Operator                     |         | 2/8/2005          | 3/16/2007         | An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. |</p>
<table>
<thead>
<tr>
<th>Continent-wide Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Telemetering</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.</td>
</tr>
<tr>
<td>Thermal Rating</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.</td>
</tr>
<tr>
<td>Tie Line Bias</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.</td>
</tr>
<tr>
<td>Time Error</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.</td>
</tr>
<tr>
<td>Time Error Correction</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An offset to the Interconnection’s scheduled frequency to return the Interconnection’s Time Error to a predetermined value.</td>
</tr>
<tr>
<td>TLR Log</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
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<td>Definition</td>
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</tr>
<tr>
<td>Total Flowgate Capability</td>
<td>TFC</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.</td>
</tr>
<tr>
<td>Total Transfer Capability</td>
<td>TTC</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.</td>
</tr>
<tr>
<td>Transfer Capability</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
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</tr>
<tr>
<td>Transmission Constraint [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>A limitation on one or more transmission elements that may be reached during normal or contingency system operations.</td>
</tr>
<tr>
<td>Transmission Customer [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.</td>
</tr>
<tr>
<td>Transmission Line [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.</td>
</tr>
<tr>
<td>Transmission Operator [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity responsible for the reliability of its &quot;local&quot; transmission system, and that operates or directs the operations of the transmission facilities.</td>
</tr>
<tr>
<td>Transmission Operator Area [Archive]</td>
<td></td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>The collection of Transmission assets over which the Transmission Operator is responsible for operating.</td>
</tr>
<tr>
<td>Transmission Planner [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.</td>
</tr>
<tr>
<td>Continent-wide Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
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</tr>
<tr>
<td>Transmission Reliability Margin [Archive]</td>
<td>TRM</td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.</td>
</tr>
<tr>
<td>Transmission Reliability Margin Implementation Document [Archive]</td>
<td>TRMID</td>
<td>08/22/2008</td>
<td>11/24/2009</td>
<td>A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator’s calculation of TRM.</td>
</tr>
<tr>
<td>Transmission Service [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.</td>
</tr>
<tr>
<td>Vegetation [Archive]</td>
<td></td>
<td>2/7/2006</td>
<td>3/16/2007</td>
<td>All plant material, growing or not, living or dead.</td>
</tr>
<tr>
<td>Wide Area [Archive]</td>
<td></td>
<td>2/8/2005</td>
<td>3/16/2007</td>
<td>The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.</td>
</tr>
</tbody>
</table>
ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

<table>
<thead>
<tr>
<th>RFC Regional Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource Adequacy</td>
<td>[Archive]</td>
<td>08/05/2009</td>
<td></td>
<td>The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)</td>
</tr>
<tr>
<td>Net Internal Demand</td>
<td>[Archive]</td>
<td>08/05/2009</td>
<td></td>
<td>Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand</td>
</tr>
<tr>
<td>Peak Period</td>
<td>[Archive]</td>
<td>08/05/2009</td>
<td></td>
<td>A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity’s annual peak demand is expected to occur</td>
</tr>
<tr>
<td>Year One</td>
<td>[Archive]</td>
<td>08/05/2009</td>
<td></td>
<td>The planning year that begins with the upcoming annual Peak Period</td>
</tr>
</tbody>
</table>
## WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

<table>
<thead>
<tr>
<th>WECC Regional Term</th>
<th>Acronym</th>
<th>BOT Approved Date</th>
<th>FERC Approved Date</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area Control Error† [Archive]</td>
<td>ACE</td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.</td>
</tr>
<tr>
<td>Automatic Time Error Correction [Archive]</td>
<td></td>
<td>3/26/2008</td>
<td>5/21/2009</td>
<td>A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection’s scheduled frequency.</td>
</tr>
<tr>
<td>Average Generation† [Archive]</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means the total MWh generated within the Balancing Authority Operator’s Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).</td>
</tr>
<tr>
<td>Disturbance† [Archive]</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.</td>
</tr>
<tr>
<td>WECC Regional Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
</tr>
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</tr>
<tr>
<td>Extraordinary Contingency†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Shall have the meaning set out in Excuse of Performance, section B.4.c.: language in section B.4.c: means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity’s reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the “Most Severe Single Contingency” as defined in the WECC Reliability Criteria or any lesser contingency).</td>
</tr>
<tr>
<td>Frequency Bias†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.</td>
</tr>
<tr>
<td>Non-spinning Reserve†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.</td>
</tr>
<tr>
<td>Normal Path Rating†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.</td>
</tr>
<tr>
<td>WECC Regional Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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<td>--------------------------------------------</td>
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</tr>
<tr>
<td>Operating Reserve†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.</td>
</tr>
<tr>
<td>Operating Transfer Capability Limit†</td>
<td>OTC</td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.</td>
</tr>
<tr>
<td>Primary Inadvertent Interchange</td>
<td></td>
<td>3/26/2008</td>
<td>5/21/2009</td>
<td>The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).</td>
</tr>
<tr>
<td>Secondary Inadvertent Interchange</td>
<td></td>
<td>3/26/2008</td>
<td>5/21/2009</td>
<td>The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).</td>
</tr>
<tr>
<td>Spinning Reserve†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).</td>
</tr>
<tr>
<td>WECC Table 2†</td>
<td></td>
<td>3/12/2007</td>
<td>6/8/2007</td>
<td>Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.</td>
</tr>
<tr>
<td>WECC Regional Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
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<td>--------------------------------------------------------</td>
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</tr>
<tr>
<td>Functionally Equivalent Protection System</td>
<td>FEPS</td>
<td>10/29/2008</td>
<td></td>
<td>A Protection System that provides performance as follows:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Each Protection System may have different components and operating characteristics.</td>
</tr>
<tr>
<td>Functionally Equivalent RAS</td>
<td>FERAS</td>
<td>10/29/2008</td>
<td></td>
<td>A Remedial Action Scheme (&quot;RAS&quot;) that provides the same performance as follows:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Each RAS may have different components and operating characteristics.</td>
</tr>
<tr>
<td>Security-Based Misoperation</td>
<td></td>
<td>10/29/2008</td>
<td></td>
<td>A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>of a device's certainty not to operate falsely.</td>
</tr>
<tr>
<td>Dependability-Based Misoperation</td>
<td></td>
<td>10/29/2008</td>
<td></td>
<td>Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>of a device's certainty to operate when required.</td>
</tr>
<tr>
<td>Commercial Operation</td>
<td></td>
<td>10/29/2008</td>
<td></td>
<td>Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>condenser has received all approvals necessary for operation after completion of initial start-up testing.</td>
</tr>
<tr>
<td>Qualified Transfer Path Curtailment Event</td>
<td></td>
<td>2/10/2009</td>
<td></td>
<td>Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1)</td>
</tr>
<tr>
<td>WECC Regional Term</td>
<td>Acronym</td>
<td>BOT Approved Date</td>
<td>FERC Approved Date</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------------</td>
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<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Relief Requirement</td>
<td></td>
<td>2/10/2009</td>
<td></td>
<td>The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority’s Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.</td>
</tr>
<tr>
<td>Transfer Distribution Factor</td>
<td>TDF</td>
<td>2/10/2009</td>
<td></td>
<td>The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]</td>
</tr>
<tr>
<td>Contributing Schedule</td>
<td></td>
<td>2/10/2009</td>
<td></td>
<td>A Schedule not in the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.</td>
</tr>
<tr>
<td>Qualified Transfer Path</td>
<td></td>
<td>2/10/2009</td>
<td></td>
<td>A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.</td>
</tr>
<tr>
<td>Qualified Controllable Device</td>
<td></td>
<td>2/10/2009</td>
<td></td>
<td>A controllable device installed in the Interconnection for controlling energy flow; the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.</td>
</tr>
</tbody>
</table>
Endnotes

† FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.
<table>
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<tr>
<th>Date</th>
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<tr>
<td>06/01/10</td>
<td>CIP Version 1 Standards</td>
<td>All Requirements and Sub-requirements</td>
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<td>MOD-001-0 thru MOD-005-0, MOD-008-0, MOD-009-0, and MOD-030-1</td>
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<td>05/03/10</td>
<td>FAC-010-2.1</td>
<td>All Requirements and Sub-requirements</td>
<td>FERC Approved — Added</td>
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<tr>
<td>04/21/10</td>
<td></td>
<td></td>
<td>Replaced the Glossary of Terms with the updated version</td>
</tr>
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<td>04/09/10</td>
<td>CIP-007-2a</td>
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<td>PRC-023-1</td>
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<td>CIP Version 3 Standards</td>
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<td>TOP-002-2a</td>
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<td>FERC Approved — Added</td>
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<td>11/02/09</td>
<td>BAL-502-RFC-02</td>
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<td>NERC BOT Approved — Added</td>
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<td>09/14/09</td>
<td>EOP-001-2, EOP-005-2, EOP-006-2, NUC-001-2</td>
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<td>NERC BOT Approved — Added</td>
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<td>Inserted Change History to End of Complete Set</td>
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<td>All Requirements and Sub-requirements</td>
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<td>NERC BOT Approved — Added</td>
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<td>MOD-021-0.1</td>
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<td>NERC BOT Approved — Added</td>
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<td>All Requirements and Sub-requirements</td>
<td>NERC BOT Approved — Added</td>
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<tr>
<td>Date</td>
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<td>Requirement</td>
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