UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. _______**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF RELIABILITY STANDARD BAL-001-2—REAL POWER BALANCING CONTROL PERFORMANCE

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April 2, 2014

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard BAL-001-2—Real Power Balancing Control Performance for Commission approval.[4] NERC requests that the Commission approve proposed Reliability Standard BAL-001-2, and associated definitions ("Regulation Reserve Sharing Group," "Reserve Sharing Group ACE," "Reporting ACE" and "Interconnection") (**Exhibit A**) and find that the proposed Reliability Standard and definitions are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5] NERC also requests approval of the associated implementation plan (**Exhibit B**), Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit F**), and retirement of Reliability Standard BAL-001-1 as detailed in this petition.

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 The BAL-001 Reliability Standard is also commonly referred to as "Control Performance Standard 1" or "CPS1."

5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

As required by Section 39.5(a)[6] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard and definitions, a summary of the development history (**Exhibit G**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (**Exhibit C**). Proposed Reliability Standard BAL-001-2 was approved by the NERC Board of Trustees on August 15, 2013.

I. EXECUTIVE SUMMARY

The purpose of proposed Reliability Standard BAL-001-2 is to maintain Interconnection frequency within predefined frequency limits. The reliable operation of an electric power system depends on careful management of the balance between generation and load to ensure that system frequency is maintained within narrow bounds around a scheduled value. The proposed Reliability Standard improves reliability by adding a frequency component to the measurement of a Balancing Authority's Area Control Error ("ACE") and allows for the formation of "Regulation Reserve Sharing Groups." Furthermore, the proposed BAL-001-2 Reliability Standard and accompanying definitions, include the benefits of the Automatic Time Error Correction ("ATEC") equation in the WECC-specific regional variance in Reliability Standard BAL-001-1.[8]

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[6] 18 C.F.R. § 39.5(a) (2013).

[7] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[8] The currently-effective BAL-001-1 Reliability Standard includes a WECC regional variance which has been incorporated into the continent-wide proposed BAL-001-2 Reliability Standard through the definition of "Reporting ACE," as explained herein. This incorporation is consistent with Commission precedent, as the Commission has noted, "The Commission seeks as much uniformity as possible in the proposed Reliability Standards across the interconnected Bulk-Power System of the North American continent." Order No. 672 at P 41.

Balancing Authorities are responsible for generation-demand-interchange balance in the Balancing Authority Area and contribute to Interconnection frequency in Real-time. ACE is the instantaneous difference between a Balancing Authority's Net Actual and Scheduled Interchange, taking into account the effects of Frequency Bias, correction for meter error, and ATEC, if operating in the ATEC mode.[9] The proposed Reliability Standard defines "Balancing Authority ACE Limit" ("BAAL") and requires a Balancing Authority to balance its resources and demand in Real-time so that its clock-minute average of its ACE does not exceed its BAAL for more than 30 consecutive clock-minutes.

The proposed Reliability Standard consists of two Requirements and two Attachments, which set forth the mathematical equations that support Requirements R1 and R2 and the accompanying Measures. Requirement R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its ACE, to support its Interconnection's frequency over a rolling one-year period. Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions. Collectively, these Requirements and Attachments support the reliability of the Bulk-Power System.

NERC requests an effective date of the first day of the first calendar quarter that is twelve months after the date of Commission approval.[10] As explained below, NERC requests that the Commission approve the proposed BAL-001-2 Reliability Standard and definitions as just and reasonable.

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[9] ATEC is only applicable to Balancing Authorities in the Western Interconnection.

[10] The proposed implementation period will allow entities to make any software adjustments that may be required to perform the BAAL calculations.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[13] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[14] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability

[11] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.
[12] 16 U.S.C. § 824o (2006).
[13] *Id.* § 824(b)(1).
[14] *Id.* § 824o(d)(5).

Standard. Section 39.5(a)[15] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[16] and Section 39.5(c)[17] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[18] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[19] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable

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15 18 C.F.R. § 39.5(a) (2012).

16 16 U.S.C. § 824o(d)(2).

17 18 C.F.R. § 39.5(c)(1).

18 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

19 The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of Project 2010-14.1: Phase 1 of Balancing Authority Reliability-Based Controls: Reserves

The NERC Standards Committee approved the merger of Project 2007-05 Balancing Authority Controls and Project 2007-18 Reliability-based Control as Project 2010-14 Balancing Authority Reliability-based Controls (commonly referred to as "BARC") on July 28, 2010. The NERC Standards Committee also approved the separation of Project 2010-14 Balancing Authority Reliability-based Controls into two phases and moving Phase 1 (Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves) into formal standards development on July 13, 2011.[20] A field trial was approved by the NERC Standards Committee and Operating Committee and is ongoing. The results of the field trial thus far support the proposed Reliability Standard and a report is currently in development.

IV. JUSTIFICATION FOR APPROVAL

The purpose of proposed Reliability Standard BAL-001-2 is to maintain Interconnection frequency within predefined frequency limits. As discussed in detail in **Exhibit C**, proposed Reliability Standard BAL-001-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[20] The BAL-002 Reliability Standard, which addresses Contingency Reserve for recovery from a balancing contingency event, is part of this consolidated project and is currently in development. The proposed BAL-001-2 Reliability Standard is not directly linked to the content of the BAL-002-2 Reliability Standard and can be approved separately.

A. BAL-001-2 – REAL POWER BALANCING CONTROL PERFORMANCE

Provided below is the following: (1) the procedural history of the BAL-001 Reliability Standard; (2) an explanation of the proposed definitions; and (3) and an explanation of the proposed BAL-001-2 Reliability Standard on a requirement-by-requirement basis.

1. Procedural History

BAL-001-0 was approved by the Commission in Order No. 693.[21] An interpretation to BAL-001-0 was accepted by the Commission in Order No. 713.[22] The Commission approved errata changes to BAL-001-0 via unpublished letter order on May 13, 2009 in Docket No. RD09-2-000. Reliability Standard BAL-001-1 was accepted by the Commission via unpublished letter order on October 16, 2013.[23]

2. Proposed Definitions

NERC proposes four definitions for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*. Provided below is the text of each proposed definition and an explanation of the need for these definitions.

- **Regulation Reserve Sharing Group**: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

The proposed definition "Regulation Reserve Sharing Group" is necessary to acknowledge that entities may form contractual arrangements in order to maintain enough Regulating Reserve.

[21] Order No. 693 at P 308.

[22] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 (2008).

[23] *N. Am. Elec. Reliability Corp.*, Docket No. RD13-11-000 (October 16, 2013)(unpublished letter order).

This proposed definition is similar in concept to the Commission-approved terms "Reserve Sharing Group" and "Frequency Response Sharing Group."[24]

- **Reserve Sharing Group Reporting ACE**: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

The proposed definition of "Reserve Sharing Group Reporting ACE" facilitates the demonstration of compliance with the BAL-001 Reliability Standard by Regulating Reserve Sharing Groups. This allows for the formation of a virtual Balancing Authority Area while allowing each individual entity to maintain their political boundaries.

- **Reporting ACE**: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

  Reporting ACE is calculated as follows:

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

  Reporting ACE is calculated in the Western Interconnection as follows:

  $$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

  Where:

  NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

  NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

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[24] *See* Order No. 693 at P 320 ("A reserve sharing group, however, as an independent organization, is able to determine on its own as a commercial matter whether any penalties related to non-compliance should be reapportioned among the members of the group."); *Frequency Response and Frequency Response Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the Frequency Bias Setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- $Y = B / B_S$.
- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1\text{-}Y) * (II_{actual} - B * \Delta TE/6)$
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}} = \text{last period's } \mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}} + \mathbf{PII_{hourly}}$$

> All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.
>
> 1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
> 2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.
> 3. The use of a common Scheduled Frequency F_S for all areas at all times.
> 4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

The proposed definition of "Reporting ACE" incorporates the equations in currently-effective Reliability Standard BAL-001-1 into the proposed definition. This proposed definition also incorporates the ATEC equation in the WECC-specific regional variance in Reliability Standard BAL-001-1.

- **Interconnection**: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

The defined term "Interconnection" is used throughout the body of NERC Reliability Standards and the proposed revision to this definition corrects the currently-effective definition, to include the Quebec Interconnection.[25] The definition of "interconnection" was approved by the Commission in Order No. 693.[26] The proposed revisions to this term are consistent with NERC's international role as the Electric Reliability Organization, pursuant to Section 215 of the Federal Power Act.

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25 The currently-effective definition of "Interconnection" is "When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT."

26 Order No. 693 at P 1898.

3. Requirement-by-Requirement Justification

Proposed Reliability Standard BAL-001-2 consists of two Requirements and is applicable to Balancing Authorities and Regulation Reserve Sharing Groups (a proposed defined term, as explained herein). Provided below is an explanation of each of the Requirements of the proposed Reliability Standard.

BAL-001-2, Requirement R1

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly.

Requirement R1 of the BAL-001 Reliability Standard is commonly referred to as Control Performance Standard 1 ("CPS1") and this terminology is maintained in the proposed Reliability Standard for historical continuity. Proposed Requirement R1 is a restatement of the BAL-001-1 Requirement R1 with the equation and explanation of the individual components moved to an attachment, Attachment 1 - *Equations Supporting Requirement R1 and Measure M1*. The proposed revisions to Requirement R1 are administratively efficient and clarify the intent of the Requirement.

Proposed Requirement R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its ACE, to support its Interconnection's frequency over a rolling one-year period. While the language of Requirement R1 has been modified, the underlying performance aspect of the Requirement is unchanged. Therefore, the Commission should approve the proposed revisions to Requirement R1.

BAL-001-2, Requirement R2

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

Proposed Requirement R2 is a new requirement intended to replace the currently-effective BAL-001-1 Requirement R2, commonly referred to as Control Performance Standard 2 ("CPS2"). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions. Attachment 2 sets forth the mathematical equations that support Requirement R2 and Measure M2.

The Balancing Authority ACE Limits ("BAAL") are unique for each Balancing Authority and provide dynamic limits for its ACE value limit as a function of its Interconnection frequency.[27] BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than Scheduled Frequency, and BAAL high is for Interconnection frequency values greater than Scheduled Frequency. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from Scheduled Frequency, the ACE limit for each Balancing Authority becomes more restrictive. The proposed Requirement R2 provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

In summary, the proposed Requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an

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[27] BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit bound measured in Hz. The Frequency Trigger Limit is equal to Scheduled Frequency, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its Frequency Trigger Limit. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its Frequency Trigger Limits.

individual Balancing Authority's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This proposed Requirement replaces and improves upon the current Requirement R2 and improves reliability by maintaining frequency within predefined limits under all conditions.

B. Enforceability of Proposed Reliability Standard BAL-001-2

The proposed Reliability Standard includes Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit F**.

The proposed Reliability Standard also includes Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[28]

[28] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

V. <u>CONCLUSION</u>

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standard and associated elements included in **Exhibit A,** effective as proposed herein;
- approve the implementation plan included in **Exhibit B**; and
- approve the retirement of Reliability Standard BAL-001-1, effective as proposed herein.

Respectfully submitted,

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Date: April 2, 2014

Exhibit A

Proposed Reliability Standard BAL-001-2

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**

2. **Number:** **BAL-001-2**

3. **Purpose:** To control Interconnection frequency within defined limits.

4. **Applicability:**

4.1. Balancing Authority

4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

5.1. 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 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, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added “a” to end of standard number In Section F, corrected automatic numbering from “2” to “1” and removed “approved” and added parenthesis to “(October 23, 2007)”	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to “0.1a”	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision
1	December 19, 2012	Adopted by NERC Board of Trustees	
2	August 15, 2013	Adopted by the NERC Board of Trustees	

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting 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 Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

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

And,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where**:**

$\mathbf{BAAL_{Low}}$ is the Low Balancing Authority ACE Limit (MW)

$\mathbf{BAAL_{High}}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

$\boldsymbol{B_i}$ is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

$\boldsymbol{F_A}$ is the measured frequency in Hz.

$\mathbf{F_S}$ is the scheduled frequency in Hz.

$\boldsymbol{FTL_{Low}}$ is the Low Frequency Trigger Limit (calculated as $F_S - 3\varepsilon 1_I$ Hz)

$\boldsymbol{FTL_{High}}$ is the High Frequency Trigger Limit (calculated as $F_S + 3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period

data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

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

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the Frequency Bias Setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\text{accum}}^{\text{on/off peak}}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- Y = B / B_S.
- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} – TE_{begin\ hour} – TD_{adj} – (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$\mathrm{PII}_{\text{accum}}^{\text{on/off peak}} = \text{last period's } \mathrm{PII}_{\text{accum}}^{\text{on/off peak}} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the

Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.
3. The use of a common Scheduled Frequency F_S for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Exhibit B

Implementation Plan for Proposed Reliability Standard BAL-001-2

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-2 – Real Power Balancing Control Performance

Approvals Required
BAL-001-2 – Real Power Balancing Control Performance

Prerequisite Approvals
None

Revisions to Glossary Terms
The following definitions shall become effective when BAL-001-2 becomes effective:

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Rreserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

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

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- Y = B / B_S.
- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.

- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$

- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\,peak} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.
3. The use of a common Scheduled Frequency FS for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

The existing definition of Interconnection should be retired at midnight of the day immediately prior to the effective date of BAL-001-2, in the jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Regulation Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-2 shall become effective as follows:

> 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 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, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The twelve-month period for implementation of BAL-001-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-2a — Reliability Coordination — Current Day Operations

IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

Exhibit C

Order No. 672 Criteria

Exhibit C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed Reliability Standard achieves the specific reliability goal of ensuring that interconnection frequency is controlled within defined limits. The proposed Reliability Standard consists of two Requirements and two Attachments, which set forth the mathematical equations that support Requirements R1 and R2 and the accompanying Measures. Requirement R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its ACE, to support its Interconnection's frequency over a rolling one-year period. Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

Collectively, these Requirements and Attachments support the reliability of the Bulk-Power System.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard applies to Balancing Authorities and Regulation Reserve Sharing Groups and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Section 4.1.1 clarifies that a Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation. Section 4.1.2 clarifies that a Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group. The requirements clearly state who is required to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The VRFs and VSLs for the proposed standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology,

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner. [5]

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Requirement R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its ACE, to support its Interconnection's frequency over a rolling one-year period. While the language of Requirement R1 has been modified, the underlying performance aspect of the Requirement is unchanged. The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all

[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

conditions. Attachment 2 sets forth the mathematical equations that support Requirement R2 and Measure M2.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed standard represents a significant improvement over the previous version as described herein.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. The proposed BAL-001-2 Reliability Standard and

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

accompanying definitions, include the benefits of the Automatic Time Error Correction ("ATEC") equation in the WECC-specific regional variance in Reliability Standard BAL-001-1.

The currently-effective BAL-001-1 Reliability Standard includes a WECC regional variance which has been incorporated into the continent-wide proposed BAL-001-2 Reliability Standard through the definition of "Reporting ACE," as explained herein. This incorporation is consistent with Commission precedent, as the Commission has noted, "The Commission seeks as much uniformity as possible in the proposed Reliability Standards across the interconnected Bulk-Power System of the North American continent." Order No. 672 at P 41.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standard does not restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability.

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[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

This will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. **Exhibit G** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and final ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests.

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[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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13 Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Mapping Document

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-001-2 Real Power Balancing Control Performance Mapping Document

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each	This Requirement has been moved into BAL-001-2 Requirement R1	Requirement R1 The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. The calculation equation for CPS1 has been moved to Attachment 1 of BAL-001-2.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. AVG_{Period} ______ $-10B$ The equation for ACE is: $ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ where: • NI_A is the algebraic sum of actual flows on all tie lines. • NI_S is the algebraic sum of scheduled flows on all tie lines. • B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz. • F_A is the actual frequency. • F_S is the scheduled frequency. F_S is normally 60		

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Hz but may be offset to effect manual time error corrections. • I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.		
R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. $AVG\text{10-minute}(ACE_i) \leq L_{10}$ where:	This Requirement has been removed from BAL-001-2 and replaced with the proposed Requirement R2 for BAAL.	Requirement R2 Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
L_{10}=1.65 ϵ_{10} ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.		The calculation equation for BAAL is located in Attachment 2 of BAL-001-2.
R3. Each Balancing Authority providing Overlap Regulation Service shall	This Requirement has been moved into the BAL-001-2	Attachment 1 A Balancing Authority providing Overlap Regulation Service

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
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.	Attachment 1.	to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving Regulation Service.
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).	This Requirement has been moved into the BAL-001-2 Applicability Section.	Applicability Section 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

Exhibit E

BAL-001-2 Real Power Balancing Control Performance Standard Background Document

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-001-2 – Real Power Balancing Control Performance Standard Background Document

July 2013

RELIABILITY | ACCOUNTABILITY




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Table of Contents

Introduction

This document provides background on the development, testing, and implementation of BAL-001-2 - Real Power Balancing Control Standard. The intent is to explain the rationale and considerations for the requirements and their associated compliance information.

The original work for this standard was done by the Balancing Authority Controls standard drafting team, which later joined with the Reliability-based Control Standard drafting team. These combined teams were renamed Balance Authority Reliability-based Control standard drafting team (BARC SDT).

The purpose of proposed Standard BAL-001-2 is to maintain Interconnection frequency within predefined frequency limits. This draft standard defines Balancing Authority ACE Limit (BAAL), and required the Balancing Authority (BA) to balance its resources and demand in Real-time so that its clock-minute average of its Area Control Error (ACE) does not exceed its BAAL for more than 30 consecutive clock-minutes.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently participating in the field trial are 13 Balancing Authorities in the Eastern Interconnection, 26 Balancing Authorities in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all Interconnections continue to monitor the performance of those participating Balancing Authorities and provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator. The Western Interconnection has experienced changes during the field trial with potential degradation to transmission; however, no explicit linkage has been determined between the field trial and these degradations. For further information on the results of the Western Interconnection, please refer to the WECC Reliability-based Control Field Trial Report.

Historical Significance

A1-A2 Control Performance Policy was implemented in 1973 as:

- A1 required the Balancing Authority's ACE to return to zero within 10 minutes of previous zero.
- A2 required that the Balancing Authority's averaged ACE for each 10-minute period must be within limits.
- A1-A2 had three main short comings:
    - Lack of theoretical justification
    - Large ACE treated the same as a small ACE, regardless of direction
    - Independent of Interconnection frequency

In 1996, a new NERC policy was approved which used CPS1, CPS2, and DCS.

CPS1is a:

- Statistical measure of ACE variability
- Measure of ACE in combination with the Interconnection's frequency error
- Based on an equation derived from frequency-based statistical theory

CPS2 is:

- Designed to limit a Control Area's (now known as a Balancing Authority) unscheduled power flows
- Similar to the old A2 criteria

The proposed BAL-001-2 retains CPS1, but proposes a new measure BAAL to replace CPS2. Currently CPS2:

- Does not have a frequency component.
- CPS2 many times give the Balancing Authority the indication to move their ACE opposite to what will help frequency.
- Only requires Balancing Authorities to comply 90 percent of the time as a minimum.

Background and Rationale by Requirement

Requirement 1

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly.

Background and Rationale

Requirement R1 is not a new requirement. It is a restatement of the current BAL-001-0.1a Requirement R1 with its equation and explanation of its individual components moved to an attachment, Attachment 1 - Equations Supporting Requirement R1 and Measure M1. This requirement is commonly referred to as Control Performance Standard 1 (CPS1). R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to support its Interconnection's frequency over a rolling one-year period.

CPS1 is a measure of a Balancing Authority's control performance as it relates to its generation, Load management, and Interconnection frequency when measured in one-minute averages over a rolling one-year period. If all Balancing Authorities on an Interconnection are compliant with the CPS1 measure, then the Interconnection will have a root mean square (RMS) frequency error less than the Interconnection's Epsilon 1.

A Balancing Authority reports its CPS1 value to its regional entity each month. This monthly value provides trending data to the Balancing Authority, NERC resources subcommittee, and others as needed to detect changes that may indicate poor control on behalf of the Balancing Authority. Requirement R1 remains unchanged, although the wording of the requirement was modified to provide clarity

Additionally, the drafting team added Regulating Reserve Sharing Group as a Responsible Entity, allowing Balancing Authorities to form Regulating Reserve Sharing Groups. This allows the Regulating Reserve Sharing Group to meet compliance as a group for CPS1. The drafting team also added the defined term Reserve Sharing Reporting ACE to facilitate Regulating Reserve Sharing Groups demonstration of compliance. This facilitates the consolidation of Balancing Authorities Areas for BAL-001 through contractual arrangements forming a virtual Balancing Authority Area while allowing each individual entity to maintain their political boundaries.

Requirement 2

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

Background and Rationale

Requirement R2 is a new requirement intended to replace existing BAL-001-0.1a Requirement R2, commonly referred to as Control Performance Standard 2 (CPS2). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

The Balancing Authority ACE Limits (BAAL) are unique for each Balancing Authority and provide dynamic limits for its Area Control Error (ACE) value limit as a function of its Interconnection frequency. BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz. The FTL is equal to Scheduled Frequency, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square (RMS) targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its FTL. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its FTL limits.

BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than Scheduled Frequency, and BAAL high is for Interconnection frequency values greater than Scheduled Frequency. BAAL values for each Balancing Authority

are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from Scheduled Frequency, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive 10-minute period was within the L_{10} bound 90 percent of all 10-minute periods over a one-month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency. For example, the Balancing Authority may be increasing or decreasing generation to meet its CPS2 bounds, even if this is a direction that reduces reliability by moving Interconnection frequency farther from its scheduled value. CPS2 allows a Balancing Authority to be outside its ACE bounds 10 percent of the time. There are 72 hours per month that a Balancing Authority's ACE can be outside its L_{10} limits and be compliant with CPS2.

In summary, the proposed BAAL requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an individual Balancing Authority's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This requirement replaces and improves upon CPS2, which is not dynamic, is not based on Interconnection frequency, and allows for a Balancing Authority's ACE value to be unbounded for a specific amount of time during a calendar month.

Change From 60Hz to Scheduled Frequency

The base frequency for the determination of BAAL was changed from 60 Hz to Scheduled Frequency, $\mathbf{F_S}$. This change was made to resolve a long-standing problem with the requirement as first presented by the Balancing Resources and Demand Standard Drafting Team. The following presents information about the reason for the initial choice of 60 Hz and the need to change this value to Scheduled Frequency.

The initial BAAL equations were developed upon the assumption that the Frequency Trigger Limit (FTL) should be based upon Scheduled Frequency as shown in this draft of the standard. During initial development of values for the FTL the BRD SDT used a deterministic method for the selection of FTL based upon the Under-Frequency Relay Limit (UFRL) of an interconnection. Since the Under-Frequency Relay Limit of the interconnection is fixed the SDT chose to use a fixed value of starting frequency that would maintain a fixed frequency difference between the FTL and the UFRL. Therefore, the BRD SDT chose to base BAAL on a starting frequency of 60 Hz

under the assumption that if the UFRL did not change then the FTL and base frequency should not change. The BAAL Field Trial was started using these values.

Shortly after the field trial started, directed research supporting the selection of the FTL for the Eastern Interconnection was completed. Unfortunately, the methods used to support the selection of an FTL for the Eastern Interconnection could not be repeated successfully for the other interconnections. Included in the final report was a recommendation that a multiple of 3 to 4 times the ε_1 for the interconnection could provide an acceptable alternative choice for determining the FTL.[1] Since the field trial had already started, no change was made to the initial FTL for the Eastern Interconnection, but as additional interconnections joined the field trial the FTL for these new interconnections was based on 3 times ε_1 for the interconnection. This change broke the linkage between FTL and the UFRL and eliminated the justification for using 60 Hz as the only acceptable starting frequency.

As data accumulated from the Eastern Interconnection field trial, it became apparent that Time Error Correction (TEC) causes a detrimental reliability impact. The BAC SDT recognized this problem and initiated actions to provide a case to eliminate TEC based on its effect on reliability. This activity caused the RBC SDT and later the BARC SDT to defer any action on the substitution of Schedule Frequency for 60 Hz in the BAAL Equations until the TEC issue was resolved because the elimination of TEC would eliminate the need for change. When the ERO decided to continue to perform TEC, that decision relieved the BARC SDT of responsibility for the reliability impact of TEC and required the team to instead consider the impact that BAAL could have on the effectiveness of the TEC process and any conflicts that would occur with other standards.

Two conflicts have been identified between BAAL and other standards. The first is a conflict between the BAAL limit and Scheduled Frequency when an interconnection is attempting to perform TEC by adjusting the Scheduled Frequency to either 59.98 of 60.02 Hz. The second is a conflict that results in BAAL providing an ACE limit that is more restrictive than CPS1 when an interconnection is performing TEC. These problems can both be resolved by basing the BAAL Limit on Scheduled Frequency instead of 60 Hz. Eight graphs follow that show the conflict between BAAL as currently defined using 60 Hz and other standards and how the change from 60 Hz to Scheduled Frequency resolves the conflict.

The first four graphs show the conflict that is created while performing TEC. Under TEC the BAAL limit crosses both the CPS1 = 100% line and the Scheduled Frequency Line indicating the conflict between BAAL, CPS1 and TEC when BAAL is based on 60 Hz.

[1] The initial value for FTL for the Eastern Interconnection was set at 50 mHz. Three time epsilon 1 for the Eastern Interconnection is 54 mHz.

The next four graphs show how this conflict is resolved by using Scheduled Frequency as the base for BAAL. When BAAL is determined in this manner both conflicts are resolved and do not appear with the implementation of TEC.

Finally, resolving this conflict reduces the detrimental impact that BAAL has on some smaller BAs on the Western Interconnection during TEC.

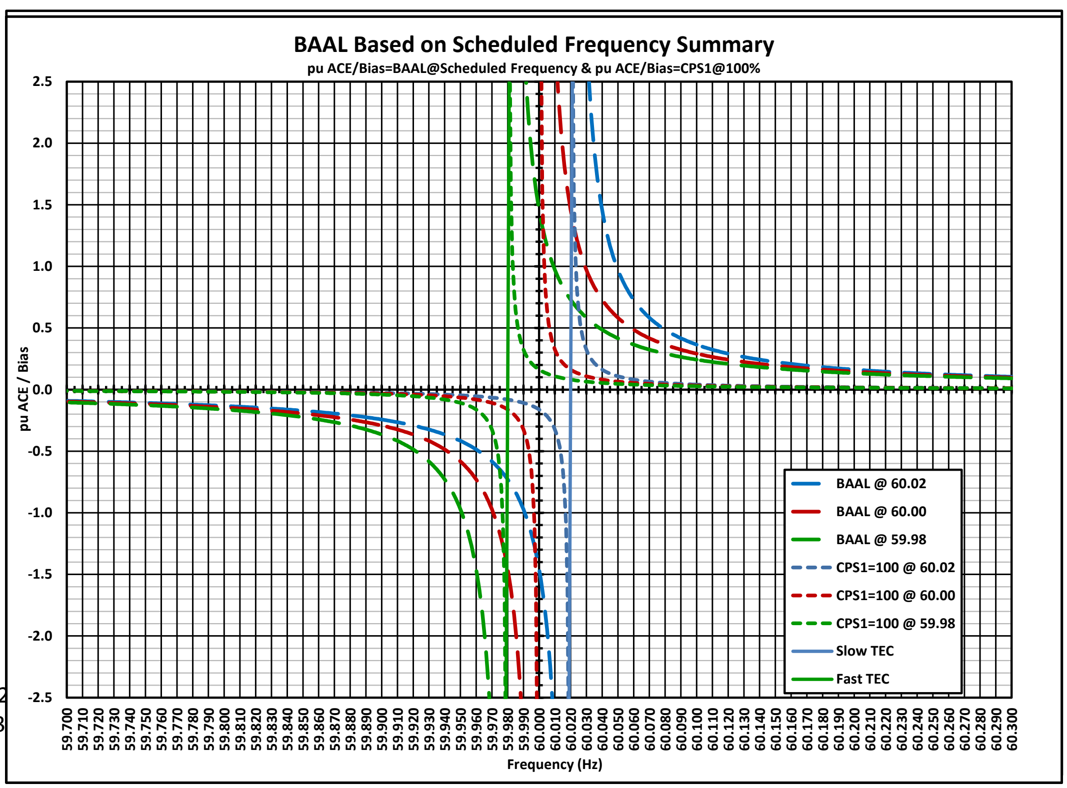

Figure 8. BAAL Based on Scheduled Frequency Summary

Exhibit F

Analysis of Violation Risk Factors and Violation Security Levels

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-001-2, Real Power Balancing Control Performance. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature, and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-001-2:
There are two requirements in BAL-001-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-001-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a Standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-001-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-001-2 are assigned a “Medium” VRF. Requirement R2 is similar in scope to Requirement R1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-001-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation-per-day basis is the "default" for penalty calculations.

VSLs for BAL-001-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated CPS1.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of intervals the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-001-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated BAAL.	This is a new requirement. As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Exhibit G

Summary of Development History and Complete Record of Development

Exhibit G - Summary of the Standard Development Proceedings and Record of Development of Proposed Definition of Bulk Electric System

The development record for the proposed revisions to the BAL-001-2 Reliability Standard is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for revisions to the BAL-001 Reliability Standard was originally posted as part of Project 2007-18 from May 15, 2007 to June 13, 2007.

There were 27 sets of comments, including comments from more than 60 different people from more than 35 companies representing 9 of the 10 industry segments.

A revised SAR was posted from September 20, 2007 to October 9, 2007. There were 21 sets of comments, including comments from more than 80 different people from more than 40 companies representing 9 of the 10 industry segments. On July 28, 2010, Project 2007-18 – Reliability-based Control, was merged with Project 2007-05 – Balancing Authority Controls, creating Project 2010-14.1—Balancing Authority Reliability-based Controls: Reserves. Project 2010-14 was separated into two phases, with phase 1 moving into formal standards development

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

on July 13, 2011. Phase 1 consists of proposed revisions to BAL-001 and BAL-002; BAL-002 is currently in development.

B. The First Posting – Formal Comment Period

The first draft of the BAL-001 Reliability Standard was posted for a formal comment period from June 4, 2012 to July 3, 2012. There were 38 sets of comments, including comments from approximately 85 companies representing 9 of the 10 industry segments.

Based on industry comments the drafting team made the following clarifying modifications to the proposed standard and associated documents.

- Created a definition for Regulation Reserve Sharing Group and Regulation Reserve Sharing Group reporting ACE.
- Removed the equation for calculating Reporting ACE from the attachment and added it to the definition.
- Modified the applicability section to provide additional clarity and remove any ambiguity.
- Made minor clarifying modifications to Requirement R1 and Requirement R2.
- Made minor clarifying modifications to the VSLs for Requirement R1 and Requirement R2.
- Modified the Background Document to provide additional clarity.

C. The Second Posting – Formal Comment Period and Initial Ballot

The second draft of the BAL-001 Reliability Standard was posted for a formal 30-day comment period from March 12, 2013 to April 25, 2013, with an initial ballot held from April 16, 2013 to April 25, 2013. The initial ballot achieved a 88.6% quorum, and an approval of 66.98%. The standard drafting team received 55 sets of comments, including comments from approximately 100 companies representing 8 of the 10 industry segments. Several changes were made to the draft of the BAL-001 Reliability Standard including:

- Made clarifying changes to the proposed standard including adding the term "…in accordance with…" in Requirement R2.
- Made clarifying changes to the definition for Reporting ACE.
- Modified the effective date to allow for 12 months to prepare for compliance with BAAL.
- Corrected typographical errors in all documents.

D. Third Posting - Final Ballot

The final ballot for the Reliability Standard was conducted from July 16, 2013 to July 25, 2013. The final ballot achieved a quorum of 92.31%, and an approval of 74.54%.

E. Board of Trustees Approval

Revisions to the BAL-001 Reliability Standard were approved by the NERC Board of Trustees on August 15, 2013.

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves

Status:
BAL-001-2 was adopted by the NERC Board of Trustees on August 15, 2013 and will be filed with the appropriate regulatory agency.

Purpose/Industry Need:
The purpose of this project is to ensure that Balancing Authorities take actions to maintain interconnection frequency with each Balancing Authority contributing its fair share to frequency control.

This project is intended to address the following:

- FERC Final Rule "Mandatory Reliability Standards for the Bulk-Power System, FERC Order 693" on the NERC standards BAL-002.

- Issues raised by stakeholders and compliance teams related to BAL-001-0.1a Real Power Balancing Control Performance and BAL-002-1 Disturbance Control Performance.

- To ensure that when finalized, the standards associated with this project conform to the latest versions of NERC's Reliability Standards Development Procedure.

Background:
The NERC Standards Committee approved the merger of Project 2007-05 Balancing Authority Controls and Project 2007-18 Reliability-based Control as Project 2010-14 Balancing Authority Reliability-based Controls on July 28, 2010. The NERC Standards Committee also approved the separation of Project 2010-14 Balancing Authority Reliability-based Controls into two phases and moving Phase 1 (Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves) into formal standards development on July 13, 2011. The Project 2010-14.1 Phase 1 proposes revisions to BAL-001-0.1a Real Power Balancing Control Performance and BAL-002-1 Disturbance Control Performance. The project also initially proposed two new standards, BAL-012-1 Operating Reserve Policy and BAL-013-1 Large Loss of Load Performance. BAL-012-1 was posted for a 45-day formal comment period with an initial ballot and non-binding poll through January 14, 2013. The initial ballot failed to achieve the required two-thirds industry approval. Based on industry comments received during this ballot period, the drafting team elected to cease any further development of the proposed BAL-012-1 standard. This project will address the FERC Order 693 Directive for development of a continent-wide Contingency Reserve standard.

The standards within Project 2010-14.1 are an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Draft	Action	Dates	Results	Consideration of Comments

BAL-002-2 Clean |Redline to Last Posting Implementation Plan Clean |Redline to Last Posting Supporting Materials: Unofficial Comment Form (Word) Background Document Clean |Redline to Last Posting Mapping Document Clean |Redline to Last Posting CR Form 1	Additional Ballot and Non-Binding Poll Updated Info>> Info>> Vote>>	12/02/13 - 12/12/13 (non-binding poll extended one additional day) (closed)	Summary>> Ballot Results>> Non-Binding Poll Results>>	
	Comment Period Info>> Submit Comments>>	10/28/13 - 12/11/13 (closed)	Comments Received>>	
BAL-002-2 Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting Supporting Materials: Unofficial Comment Form (Word) Background Document	Additional Ballot Updated Info>> Vote>>	09/06/13 - 09/17/13 (non-binding poll extended one additional day) (closed)	Summary>> Ballot Results>> Non-binding Poll Results>>	Consideration of Comments>>
	Comment Period Info>> Submit Comments>>	08/02/13 - 09/17/13 (closed)	Comments Received>>	

Clean | Redline to Last Posting VRF/VSL Justification Mapping Document Clean | Redline to Last Posting CR Form 1				
BAL-001-2 Clean (26) | Redline to Last Posting (27) Implementation Plan Clean (28) | Redline to Last Posting (29) **Supporting Materials:** Background Document Clean (30) | Redline to Last Posting (31) VRF/VSL Justification Clean (32) | Redline to Last Posting (33) Mapping Document Clean(34) | Redline to Last Posting (35)	Final Ballot Info (36) Vote>>	07/16/13 - 07/25/13 (closed)	Summary (37) Ballot Results (38)	
BAL-001-2 Clean (10) Redline to Last Posting (11)	Initial Ballots and Non-binding Polls Info (19) Vote>>	04/16/13 - 04/25/13 (closed)	Summary (21) **Ballot Results:** BAL-002-2	Consideration of Comments: BAL-001-2 (25) BAL-002-2

Implementation Plan Clean (12) Redline to Last Posting (13) BAL-002-2 Clean Redline to Last Posting Implementation Plan Clean | Redline to Last Posting BAL-013-1 Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting **Supporting Materials:** Unofficial Comment Forms (Word) BAL-001-2 (14) BAL-002-2 BAL-013-1 **Background Documents:**	Formal Comment Period Info (20) Submit Comments>> BAL-001-2 BAL-002-2 BAL-013-1	03/12/13 - 04/25/13 (closed)	BAL-001-2 (22) BAL-013-1 **Non-binding Poll Results:** BAL-001-2 (23) BAL-002-2 BAL-013-1 -------- **Comments Received:** BAL-001-2 (24) BAL-002-2 BAL-013-1	
	Join Ballot Pools>> Join	03/12/13 - 04/10/13 (closed)		

BAL-001-2 Clean (15) | Redline to Last Posting (16) BAL-002-2 Clean BAL-013-1 Clean | Redline to Last Posting **Mapping Documents** BAL-001-2 (17) BAL-002-2 **VRF/VSL Justification** BAL-001-2 (18) BAL-002-2 BAL-013-1				
Draft 2 BAL-012-1 Clean | Redline to Last Posting Supporting Materials: Unofficial Comment Form (Word) Background Document	Initial Ballot and Non-Binding Poll Updated Info>> Info>> Vote>>	1/4/2012 – 1/14/2013 (closed)	Summary>> Update Ballot Results>> Non-binding Poll Results>>	
	Formal Comment Period Info>> Submit Comments>>	11/30/2012 – 1/14/2013 (closed)	Comments Received>>	

Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting VRF/VSL Justification	Join Ballot Pool Join>>	11/30/2012 – 1/3/2013 (closed)		
Draft 1 **BAL-001-1** Clean (1) **Supporting Materials:** Unofficial Comment Form (Word) (2) BAL-001-0.1a (3) Background Document (4) Implementation Plan (5) Mapping Document (6) VRF/VSL Justification (7)	**Formal Comment Period** Info (8) Submit Comments>> Comment Form - BAL-001-1	6/4/2012 - 7/3/2012 (closed)	Comments Received (9)	Consideration of Comments>>(39)
Draft 1 BAL-002-2 Clean Supporting Materials: Unofficial Comment Form (Word) BAL-002-1 Background	Formal Comment Period Info>> Submit Comments>> Comment Form - BAL-002-2	6/4/2012 - 7/3/2012 (closed)	Comments Received>>	

Document Implementation Plan Mapping Document				
Draft 1 BAL-012-1 Clean Supporting Materials: Unofficial Comment Form (Word) Background Document Implementation Plan	Formal Comment Period Info>> Submit Comments>> Comment Form - BAL-012-1	6/4/2012 - 7/3/2012 (closed)	Comments Received>>	Consideration of Comments>>
Draft 1 BAL-013-1 Clean Supporting Materials: Unofficial Comment Form (Word) Background Document Implementation Plan	Formal Comment Period Info>> Submit Comments>> Comment Form - BAL-013-1	6/4/2012 - 7/3/2012 (closed)	Comments Received>>	

Standard Development Roadmap

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

Development Steps Completed:

1. The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal comment period on May 15, 2007.
2. A revised SAR for Project 2007-05, Reliability Based Controls, was posted for a second 30-day formal comment period on September 10, 2007.
3. The Standards Committee approved Project 2007-18, Reliability Based Controls, to be moved to standard drafting on December 11, 2007.
4. The SAR for Project 2007-05, Balancing Authority Controls, was posted for a 30-day formal comment period on July 3, 2007.
5. The Standards Committee approved Project 2007-05, Balancing Authority Controls, to be moved to standard drafting on January 18, 2008.
6. The Standards Committee approved the merger of Project 2007-05, Balancing Authority Controls, and Project 2007-18, Reliability-based Controls, as Project 2010-14, Balancing Authority Reliability-based Controls, on July 28, 2010.
7. The NERC Standards Committee approved breaking Project 2010-14, Balancing Authority Reliability-based Controls, into two phases; and moving Phase 1 (Project 2010-14.1, Balancing Authority Reliability-based Controls – Reserves) into formal standards development on July 13, 2011.

Proposed Action Plan and Description of Current Draft:

This is the first posting of the proposed new standard. This proposed draft standard will be posted for a 30-day formal comment period beginning on June 4, 2012 through July 3, 2012.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Second posting	October/November 2012
2. Initial Ballot	November 2012
3. Recirculation Ballot	March 2013
4. NERC BOT adoption.	March 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority ACE Limit (BAAL): The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit ($BAAL_{High}$) and a low limit ($BAAL_{Low}$).

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, as defined in BAL-001, which includes the difference between the Balancing Authority's actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error.

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, Texas and Quebec.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** **BAL-001-1**
3. **Purpose:** **To control Interconnection frequency within defined limits.**
4. **Applicability:**

4.1. Balancing Authority

4.1.1 A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE, and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

4.1.2 A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Regulation Service.

4.1.3 A Balancing Authority receiving Overlap Regulation Service is not subject to CPS1 or BAAL compliance evaluation.

5. **(Proposed) Effective Date:**

5.1. First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly, to support Interconnection frequency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support Interconnection frequency.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority shall provide evidence, upon request; such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request; such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The regional entity is the compliance enforcement authority, except where the responsible entity works for the regional entity. Where the responsible entity works for the regional entity, the regional entity will establish an agreement with the ERO, or another entity approved by the ERO and FERC (i.e., another regional entity), to be responsible for compliance enforcement.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Balancing Authority shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its compliance enforcement authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting Ace is calculated for the current year, plus three previous calendar years.

If a Balancing Authority is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The compliance enforcement authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Balancing Authority's area value of CPS1, on a rolling 12-month basis, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The Balancing Authority's area value of CPS1, on a rolling 12-month basis, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The Balancing Authority's area value of CPS1, on a rolling 12-month basis, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The Balancing Authority's area value of CPS1, on a rolling 12-month basis, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but less than or equal to 45 consecutive clock minutes.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but less than or equal to 60 consecutive clock minutes.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but less than or equal to 75 consecutive clock minutes.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes.

E. Regional Variances

None.

F. Associated Documents

BAL-001-1, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and exclusion of CPS2	Revision

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters over a 12-month period, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent consecutive 12 months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.

Reporting ACE is calculated as follows:

$$\textbf{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - NME$$

Where:

NI_A (Net Interchange Actual) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Net Interchange Schedule) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz, with minimum resolution of +/- 0.0005 Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

NME (Net Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NI_A) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE and for Frequency Error) for each sampling cycle during a given clock minute.

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

and,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

A Balancing Authority receiving Overlap Regulation Service is not subject to CPS1compliance evaluation.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to 60 Hz, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than 60 Hz, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - 60\right)\right) \times \frac{\left(FTL_{Low} - 60\right)}{\left(F_A - 60\right)}$$

When actual frequency is greater than 60 Hz, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - 60\right)\right) \times \frac{\left(FTL_{High} - 60\right)}{\left(F_A - 60\right)}$$

Where**:**

$\mathbf{BAAL_{Low}}$ is the Low Balancing Authority ACE Limit (MW)

$\mathbf{BAAL_{High}}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

$\boldsymbol{B_i}$ is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

$\boldsymbol{F_A}$ **is** the measured frequency in Hz, with a minimum resolution of +/- 0.0005 Hz.

$\boldsymbol{FTL_{Low}}$ is the Low Frequency Trigger Limit (calculated as $60\text{-}3\varepsilon 1_I$ Hz)

$\boldsymbol{FTL_{High}}$ is the High Frequency Trigger Limit (calculated as $60+3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the BAAL calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Regulation Service.

A Balancing Authority receiving Overlap Regulation Service is not subject to BAAL compliance evaluation.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-001-1 – Real Power Balancing Control Performance

Please **do not** use this form to submit comments on the proposed revisions to BAL-001-1 Real Power Balancing Control Performance. Comments must be submitted on the electronic comment form by 8 p.m. **July 3, 2012**. If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

BAL-001-1 Real Power Balancing Control Performance

Background Information:

Control Performance Standard 1 (CPS1) has been retained, and details for calculating CPS1 are included in Attachment 1. Calculation of Reporting Area Control Error (Reporting ACE) has been clarified, and details for calculating Reporting ACE are also included in Attachment 1. The Balancing Authority ACE Limit (BAAL), an interconnection frequency and Balancing Authority ACE measurement, is included in this standard as Requirement 2 and replaces Control Performance Standard 2 (CPS2). Details for the calculation of BAAL are included in Attachment 2.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L10. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive ten minute period was within the L10 bound 90 percent of all 10 minute periods over a one month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency.

BAAL is defined by two equations, BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than 60 hertz and BAAL high is for Interconnection frequency values greater than 60 hertz. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from 60 hertz, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently there are 13 Balancing Authorities participating in the Eastern Interconnection, 26 Balancing Authorities participating in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all interconnections continue to monitor the performance of those participating Balancing Authorities and

provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The BARC SDT has developed two new terms to be used with this standard.**

   Balancing Authority ACE Limit (BAAL):

   The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit (BAALHigh) and a low limit (BAALLow).

   Reporting ACE:

   The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW as defined in BAL-001 which includes the difference between the Balancing Authority's actual interchange and its scheduled interchange plus its frequency bias obligation plus any known meter error.

   Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

2. **The SDT has modified the definition for the term Interconnection. The new definition is shown below in redline to show the changes proposed.**

   Interconnection:

   When capitalized, any one of the four~~three~~ major electric system networks in North America: Eastern, Western, Texas and Quebec~~ERCOT~~.

   Do you agree with this new definition for Interconnection? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

3. **The proposed Purpose Statement for the draft standard is:**

To control Interconnection frequency within defined limits in support of interconnection frequency.

Do you agree with this purpose statement? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

4. **The BARC SDT has developed Requirement R1 to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to supports its Interconnection's frequency over a rolling one year period.**

   R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly, to support interconnection frequency.

   Do you agree with this Requirement? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

5. **The BARC SDT has developed Requirement R2 to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.**

   R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support interconnection frequency.

   Do you agree with this Requirement? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

6. **The BARC SDT has developed VRFs for the proposed Requirements within this standard. Do you agree that these VRFs are appropriately set? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

7. The BARC SDT has developed Measures for the proposed Requirements within this standard. Do you agree with the proposed Measures in this standard? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

8. The BARC SDT has developed VSLs for the proposed Requirements within this standard. Do you agree with these VSLs? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

9. The BARC SDT has developed a document "BAL-001-1 Real Power Balancing Control Standard Background Document" which provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

10. If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.

Comments:

11. Do you have any other comment on BAL-001-1, not expressed in the questions above, for the BARC SDT?

Comments:

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: BAL-001-0.1a
3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability**:
   4.1. Balancing Authorities
5. **Effective Date:** 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 ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

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

The equation for ACE is:

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

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

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

where:

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

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

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

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

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

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

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority’s valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

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

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

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

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

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

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

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

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

The 12-month compliance factor becomes:

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

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

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

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

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

Violation clock-ten-minutes

= 0 if

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

= 1 if

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

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

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

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

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

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

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

3. Levels of Non-Compliance – CPS2

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

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

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

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

E. Regional Differences

1. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

F. Associated Documents

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

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	

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

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

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

Appendix 2

Interpretation of Requirement 1

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

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

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

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

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-001-1 – Real Power Balancing Control Performance Standard Background Document

January 2012

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Introduction

This document provides background on the development, testing, and implementation of BAL-001-1 - Real Power Balancing Control Standard. The intent is to explain the rationale and considerations for the requirements and their associated compliance information.

The original work for this standard was done by the Balancing Authority Controls standard drafting team, which later joined with the Reliability-based Control Standard drafting team. These combined teams were renamed Balance Authority Reliability-based Control standard drafting team (BARC SDT).

The purpose of proposed Standard BAL-001-1 is to maintain Interconnection frequency within predefined frequency limits. This draft standard defines Balancing Authority ACE Limit (BAAL), and required the Balancing Authority (BA) to balance its resources and demand in Real-time so that its clock-minute average of its Area Control Error (ACE) does not exceed its BAAL for more than 30 consecutive clock-minutes.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently participating in the field trial are 13 Balancing Authorities in the Eastern Interconnection, 26 Balancing Authorities in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all Interconnections continue to monitor the performance of those participating Balancing Authorities and provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

Historical Significance

A1-A2 Control Performance Policy was implemented in 1973 as:

- A1 required the Balancing Authority's ACE to return to zero within 10 minutes of previous zero.
- A2 required that the Balancing Authority's averaged ACE for each 10-minute period must be within limits.
- A1-A2 had three main short comings:
  - Lack of theoretical justification
  - Large ACE treated the same as a small ACE, regardless of direction
  - Independent of Interconnection frequency

In 1996, a new NERC policy was approved which used CPS1, CPS2, and DCS.

CPS1is a:

- Statistical measure of ACE variability
- Measure of ACE in combination with the Interconnection's frequency error

- Based on an equation derived from frequency-based statistical theory

CPS2 is:

- Designed to limit a Control Area's (now known as a Balancing Authority) unscheduled power flows
- Similar to the old A2 criteria

The proposed BAL-001-1 retains CPS1, but proposes a new measure BAAL. Currently CPS2:

- Does not have a frequency component.
- CPS2 many times give the Balancing Authority the indication to move their ACE opposite to what will help frequency.
- Requires Balancing Authorities to comply 90 percent of the time as a minimum.

Background and Rationale by Requirement

Requirement 1

R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1) (as calculated in Attachment 1) is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly, to support Interconnection frequency.

Background and Rationale

Requirement R1 is not a new requirement. It is a restatement of the current BAL-001-0.1a Requirement R1 with its equation and explanation of its individual components moved to an attachment, Attachment 1 - Equations Supporting Requirement R1 and Measure M1. This requirement is commonly referred to as Compliance Performance Standard 1 (CPS1). R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to support its Interconnection's frequency over a rolling one-year period.

CPS1 is a measure of a Balancing Authority's control performance as it relates to its generation, Load management, and Interconnection frequency when measured in one-minute averages over a rolling one-year period. If all Balancing Authorities on an Interconnection are compliant with the CPS1 measure, then the Interconnection will have a root mean square (RMS) frequency error less than the Interconnection's Epsilon 1.

A Balancing Authority reports its CPS1 value to its regional entity each month. This monthly value provides trending data to the Balancing Authority, NERC resources subcommittee, and others as needed to detect changes that may indicate poor control on behalf of the Balancing

Authority. Requirement R1 remains unchanged, although the wording of the requirement was modified to provide clarity.

Requirement 2

R2. Each Balancing Authority shall operate such that its clock-minute average of reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL) (as calculated in Attachment 2) for the applicable Interconnection in which it operates to support Interconnection frequency.

Background and Rationale

Requirement R2 is a new requirement intended to replace existing BAL-001-0.1a Requirement R2, commonly referred to as Control Performance 2 (CPS2). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

The Balancing Authority ACE Limits (BAAL) are unique for each Balancing Authority and provide dynamic limits for its Area Control Error (ACE) value limit as a function of its Interconnection frequency. BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz. The FTL is equal to 60 Hz, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square (RMS) targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its FTL. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its FTL limits.

BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than 60 Hz, and BAAL high is for Interconnection frequency values greater than 60 Hz. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from 60 Hz, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive 10-minute period was within the L_{10} bound 90 percent of all 10-minute periods over a one-month period. While this standard does require the Balancing

Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency. For example, the Balancing Authority may be increasing or decreasing generation to meet its CPS2 bounds, even if this is a direction that reduces reliability by moving Interconnection frequency farther from its scheduled value. CPS2 allows a Balancing Authority to be outside its ACE bounds 10 percent of the time. There are 72 hours per month that a Balancing Authority's ACE can be outside its L_{10} limits and be compliant with CPS2.

In summary, the proposed BAAL requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an individual Balancing Authority's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This requirement replaces and improves upon CPS2, which is not dynamic, is not based on Interconnection frequency, and allows significant hours when a Balancing Authority's ACE values are unbounded.

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-1 – Real Power Balancing Control Performance

Approvals Required
BAL-001-1 – Real Power Balancing Control Performance

Prerequisite Approvals
None

Revisions to Glossary Terms
The following definitions shall become effective when BAL-001-1 becomes effective:

> **Balancing Authority ACE Limit (BAAL):** The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit ($BAAL_{High}$) and a low limit ($BAAL_{Low}$).
>
> **Reporting ACE:** The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, as defined in BAL-001, which includes the difference between the Balancing Authority's actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error.
>
> **Interconnection:** When capitalized, any one of the four major electric system networks in North America: Eastern, Western, Texas and Quebec.

The existing definition of Interconnection should be retired at midnight of the day immediately prior to the effective date of BAL-001-1, in the jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-1 shall become effective as follows:

> First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-001-1 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning

IRO-005-2a — Reliability Coordination — Current Day Operations
IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-001-1 Real Power Balancing Control Performance Mapping Document

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-1		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-1**
R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each	This Requirement has been moved into BAL-001-1 Requirement R1	Requirement R1 Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly, to support interconnection frequency. The calculation equation for CPS1 has been moved to Attachment 1 of BAL-001-1.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-1		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-1**
Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. $AVG_{Period}\,\underline{ACE1}$ $-10B$ The equation for ACE is: $ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$ where: • NI_A is the algebraic sum of actual flows on all tie lines. • NI_S is the algebraic sum of scheduled flows on all tie lines. • B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz. • F_A is the actual frequency. • F_S is the scheduled frequency. F_S is normally 60		

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-1		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-1**
Hz but may be offset to effect manual time error corrections. • I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.		
R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. AVG10-minute $(ACE_i) \leq L_{10}$ where:	This Requirement has been removed from BAL-001-1 and replaced with the proposed Requirement R2 for BAAL.	Requirement R2 Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support interconnection frequency.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-1		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-1**
$L_{10}=1.65\,\epsilon_{10}\sqrt{(-10B_i)(-10B_s)}$ ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.		The calculation equation for BAAL is located in Attachment 2 of BAL-001-1.
R3. Each Balancing Authority providing Overlap Regulation Service shall	This Requirement has been moved into the BAL-001-1	Applicability Section 4.1.1 and Attachment 1 A Balancing Authority providing Overlap Regulation Service

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-1		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-1**
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.	Applicability Section and Attachment 1.	to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving Regulation Service.
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).	This Requirement has been moved into the BAL-001-1 Applicability Section and Attachment 1.	Applicability Section 4.1.3 and Attachment 1 A Balancing Authority receiving Overlap Regulation Service is not subject to CPS1 or BAAL compliance evaluation.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-001-1, Real Power Balancing Control Performance. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature, and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-001-1:
There are two requirements in BAL-001-1. Both requirements were assigned a "Medium" VRF.

VRF for BAL-001-1, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-003-1 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a Standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-001-1, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-003-1 are assigned a “Medium” VRF. Requirement R2 is similar in scope to Requirement R1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-001-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation-per-day basis is the "default" for penalty calculations.

VSLs for BAL-001-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated CPS1.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of intervals the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-001-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated BAAL.	This is a new requirement. As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves

Formal Comment Period Open: June 4 – July 3, 2012

Now Available

Formal comment periods are open for the following four standards: **BAL-001-1** - Real Power Balancing Control Performance, **BAL-002-2** - Contingency Reserve for Recovery from a Balancing Contingency Event, **BAL-012-1** - Operating Reserve Planning, and **BAL-013-1** - Large Loss of Load Performance through 8 p.m. Tuesday, July 3, 2012.

Instructions for Commenting

Formal comment periods are open through **8 p.m. Eastern on Tuesday, July 3, 2012.**

Please use following comment forms to submit comments:
Comment Form – BAL-001-1
Comment Form – BAL-002-2
Comment Form – BAL-012-1
Comment Form – BAL-013-1

Due to the length of the definitions and the formatting limitations of the electronic commenting software, please refer to the Unofficial Comment Form in Word on the project page for redlines referenced in Question Two for BAL-001-1 in the electronic comment form.

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of each of the comment forms is posted on the project page.

Next Steps

The drafting team will consider all comments and determine whether to make changes to the standards and associated documents. After the standards and associated documents are revised, the drafting team will submit its work for quality review prior to the next posting.

Background

The NERC Standards Committee approved the merger of Project 2007-05 Balancing Authority Controls and Project 2007-18 Reliability-based Control as Project 2010-14 Balancing Authority Reliability-based Controls on July 28, 2010. The NERC Standards Committee also approved the separation of Project 2010-14 Balancing Authority Reliability-based Controls into two phases and moving Phase 1 (Project 2010-14.1 Balancing Authority Reliability-based Controls – Reserves) into formal standards development on July 13, 2011. The Standard

Drafting Team has revised BAL-001-0.1a Real Power Balancing Control Performance and BAL-002-1 Disturbance Control Performance. The Standard Drafting Team proposes to eliminate the CPS2 metric in the present BAL-001-01a standard and replace it with a new Balancing Authority ACE limits metric. The Standard Drafting Team has completely revised the current BAL-002-1 standard to eliminate the ambiguity and move requirements from the "Additional Compliance Information" section into the requirements section. The Standard Drafting Team is also proposing two new standards BAL-012-1 Operating Reserve Planning, and BAL-013-1 Large Loss of Load Performance to address planning for Regulating, Contingency and Frequency Responsive Reserves and responding to a Large Loss of Load event.

The four standards within Project 2010-14.1 are an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend out thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Name (22 Responses)
Organization (22 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (32 Responses)
Question 1 Comments (36 Responses)
Question 2 (31 Responses)
Question 2 Comments (36 Responses)
Question 3 (31 Responses)
Question 3 Comments (36 Responses)
Question 4 (30 Responses)
Question 4 Comments (36 Responses)
Question 5 (33 Responses)
Question 5 Comments (36 Responses)
Question 6 (27 Responses)
Question 6 Comments (36 Responses)
Question 7 (28 Responses)
Question 7 Comments (36 Responses)
Question 8 (27 Responses)
Question 8 Comments (36 Responses)
Question 9 (30 Responses)
Question 9 Comments (36 Responses)
Question 10 (0 Responses)
Question 10 Comments (36 Responses)
Question 11 (0 Responses)
Question 11 Comments (36 Responses)

Group
LG&E and KU Services
Brent ingebrigtson
Yes
LG&E and KU Services suggest removing “reliability risk” from the end of the first sentence in the BAAL definition
No
The posted BAL-001-1 shows the Purpose Statement as: Purpose: To control Interconnection frequency within defined limits. The purpose statement in the draft standard is preferred over the Purpose Statement as shown in Question 3.
Yes
LGE and KU Services is a participant in the BAAL Field Test and support the implementation of the BAAL standard.
LG&E and KU Services suggests that the SDT clarifies that the standard will not require monthly reporting as if currently performed by the BA (CPS1 and BAAL) to SERC/NERC/FERC but that the BA will need to evaluate CPS1 monthly and BAAL continuously.
Individual
Robert Blohm
Keen Resources Asia Ltd.

Yes
Yes
Yes
Delete "in support of interconnection frequency". It's redundant, and childishly repetitive of the same term. You don't control something to within limits in order to undermine (= not support) those limits!
Yes
Yes
Yes
Yes
Yes
No
No. In particular this sentence on page 5 of the background document provides no technical justification for the the "3" in the plus/minus 3epsilon FTL: "BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz." The analysis commissioned by NERC without tender to an outside software vendor was demolished in the extensive posted comments by 2 statistical experts, California ISO and NPCC. The analysis was junked together with the rejected proposed standard as NERC proceeded to form a new drafting team to rebuild the standard. 3 has been demonstrated throughout the field test to be too tight in terms of generating too many BAAL exceedences to be addressed immediately by the BA. The BA needs to wait at least 5 minutes for enough of these exceedences to go away to leave a feasible/manageable number begin to addressing. Such waiting jeopardizes reliability. It is much more prudent to raise the "3" to somewhere between 4 or 5 to generate exceedences small enough in number to be feasible/manageable to begin addressing immediately upon occurrence. Setting the FTL at a high enough threshold where the number of exceedences becomes feasible or manageable enough to be addressed immediately upon occurrence instead of 5 or more minutes after they have begun if FTL is set at too low a multiple of epsilon, is least expensive and most favorable to reliability. The field test has not "proved" that 3 is the proper multiple just because there has been no blackout. Otherwise we can go home until the next blackout. Instead the field test has produced the data supporting the contention that the limit is too tight for reliability because it generates too many short-lived exceedences and thereby encourages waiting to address the exceedences that will persist and be very serious. After the demise of the previous proposed standard, NERC elected to change policy and stop commissioning research and therefore development of any thorough technical justification for the present proposed standard. In other words, NERC can no longer justify a reliability standard by any documented scientific procedure of its own.
The technically unjustified tight multiple of "3" epsilon (versus between 4 and 5) in the Frequency Trigger Limit (FTL) on page 10 (Attachment 2) of the Standard violates (1) the requirement that reliability standards not interfere with the "just and reasonable" economic basis for market efficiency and (2) the requirement that reliability standards improve not reduce reliability. Point (2) is covered in my comments to Question 9. The multiple of 3 raises reliability cost not just unnecessarily, but perversely in exchange for less reliability. That interferes with the normal "just and reasonable" cost/price basis for markets that must allow for costs of necessary reliability provided those costs are allocated in a way that is just and reasonable and not perverse to reliability. It is well-known that, by Bayesian "multiplication" of "conditional" probability, the probability of being at the FTL is "multiplied by" (not "added to") the "conditional" probability of the system's having a once-in-ten-years event provided it is at the FTL, and is an infinitesimal fraction of the probability of the system's reaching a once-in-ten-years event. Probabilities are fractions of 1. A fraction times a fraction is an infinitesimal. Contrary to the transmission/congestion engineer's deterministic practice of "adding" transmission

capacities/contingencies, contingent/conditional probabilities are multiplied, not added. Transmission management/planning practices are not applicable to generation/load frequency control. Accordingly the FTL, regardless of whether the multiple of epsilon is 3, 4 or 5, is already in the realm one-event-in hundreds, thousands of years. So, there is no issue that a higher ("5") or lower ("3") multiple of epsilon is in a "dangerous" zone of unreliability. The issue is more of how "unnecessarily" tight the limit is in terms of adding to the cost of operations that participants then seek to avoid by ignoring the limit for the initial five or more minutes of a BAAL exceedence and thereby more than undo the supposed reliability benefit of the tightness!
Group
ISO's Standards Review Committee
Terry Bilke
No
The definition of reporting ACE is nearly identical to the current definition of ACE, but the appendix adds complexity. There should be no need for this new definition. The description of the definition in the attachment is overly prescriptive. It has a redundant and more restrictive requirement for frequency resolution than BAL-005. It also created a new term, Net Metering Error that is more prescriptive than how metering error is corrected for today.
No
While we agree that these four entities comprise the four major Interconnections, the term is used scores of times in other standards. It is beyond the scope of this drafting team to redefine expectations of other standards.
Yes
Yes
1)While we agree that the 12 month rolling average performance is evaluated monthly, that does not mean that substandard performance in one month should result in many months of repeat violations until that bad month rolls out the average. Non-compliance should only accrue if the BA is not under a mitigation plan and has new months of non-compliant performance. 2)The purpose of averaging is to account for both the good and bad performances experienced over the 12 months in question. We suggest that the SDT develop a criterion that identifies a given month performance as being out of limits and that the performance is so good or so bad that the monthly value either be dropped from the averaging or it be substituted with the limiting value.
Yes
Yes
Yes
Yes
The drafting team may want to look at how small BAs are impacted by R2. The CPS curve for small BAs has a wider tail. The performance expectations may not be the same.
No
1) If the background document is expected to be used just to explain the team’s work, we have no issue with it. If it is expected to replace the current Performance Standards Reference Guidelines in the NERC Operating Manual, the document lacks significant detail. 2) While it is not material to the new standard, the A1 criteria is not properly stated. Under A1, ACE needed to cross zero at least once in every ten minute period of the hour and that the total non-crossings had to be less than 10 percent of all periods.
1)The concept of a definition is to provide a generic baseline that allows other descriptive items to be identified. For example: An Interconnection could be defined as a collection of loads, suppliers and transmission that operates synchronously. The Eastern Interconnection would be understood to be

that group of … 2)BAAL should be incorporated within a requirement as a performance level. It should not be a definition. 3)Similarly with ACE. ACE is defined as S-A + B delta f. The scan rate details are subsets of that definition; they are not the definition. 4)The applicable entities should not be defined by the methodology they use to meet the standard, nor should requirements be placed in the Applicable entity definition. 5)Sections 4.1.1 and 4.1.2 are unclear as to which entities are subject to complying with the standard. Further, the word “calculates” in both Sections turn these Sections into requirements rather than specifying the entities being responsible for meeting Requirements R1 and R2. 6)Inferring from Section 4.1.3, we interpret these Sections to mean that the “Balancing Authority that provides Overlap Regulation Service to another Balancing Authority”. In that case, a requirement to hold the service providing BAs responsible for calculating its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE, and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service, would be necessary. Same applies to the BAAL calculation implied in Section 4.1.3
Individual
Mike Goodenough
pwx
Yes
Yes
No
No, the Purpose Statement is inadequate. The purpose of the standard should be to control BAA ACE within defined limits in support of Interconnection Frequency, and to prevent BAA ACE from having a detrimental impact to other entities on the grid. In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for inadvertent energy flows between adjacent BAs to both jeopardize reliability and to cause undue harm to customers on the grid. Such inadvertent energy flows are driven by the size of each BAAs ACE, as primarily contained by CPS2 under the current BAL-001, and the new proposed BAL-001 standard. Powerex believes that the development of the BAL-001 standard based on the current purpose statement will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impact to transmission customers on the grid. This may result in substantial curtailments to transmission customers in direct contravention of the Commission’s open access transmission principles.
Yes
No
No. The standard is inadequate. The requirement will allow BA’s to operate in a way that could significantly increase risk to the interconnection, for up to 30 minutes, without penalty. Worse, it will allow BA’s to “sawtooth”: operate outside the BAAL limit for extended periods of time (up to 30 minutes), change operations for as little as one minute to bring their ACE back into the BAAL limit to reset the 30 minute clock, and then again start operating outside the BAAL limit, and do so cyclically, for extended periods. This behavior was exhibited to some extent by several BAsduring the field trial, so there should be every expectation that this type of behavior will continue, if not spread and worsen, if this new standard was put in place. In the Background Document for the standard the drafting team pointed out that CPS2 “… allows significant hours when a Balancing Authority’s ACE values are unbounded.” Because R2 of the proposed standard will allow BAs to cyclically operate outside the BAAL limit as described above, the problem of BA’s operating with an unbounded ACE could actually become worse under the proposed standard, not better. Powerex notes that no technical justification has been put forward as to why a BAA should be able to operate outside the BAAL limit for 30 minutes. We recommend that the drafting team consider a shorter period (e.g. 5 minutes). As well, to prevent the sawtoothing behavior, Powerex recommends that a monthly maximum be set on the number of times a BAA can exceed the BAAL limit (e.g. 5 times per month). Another concern is that the requirement will allow unlimited unscheduled flow, across interties when the actual system frequency is close to the scheduled frequency. There seems to be a disregard for the fact that unscheduled flows can have a significant detrimental impact on scheduled flows. Curtailments to scheduled flows is one of the main tools used to keep the system operating within

limits during period of high unscheduled flows, effectively giving unscheduled flows priority access over the rights paid for by OATT customers (scheduled flows). For example, during the RBC trial in the West, the number of curtailments to e-tags went up dramatically as a result of unscheduled flows across path 36, as reported by the WECC Performance Workgroup in the December 2011 Quarterly Report on the RBC Field Trial. Most recently, we have seen a record number of curtailments across path 66. In 2011, there were a total of 61 Path 66 events of Step 4 or higher (see WECC Unscheduled Flow Reduction Guideline). Already in 2012, we have seen 741 Path 66 events of step 4 or higher (as of mid June). It is a significant concern that the higher unscheduled flows resulting from the RBC field trial are contributing to the curtialments. If the proposed standard is approved it should be expected that this issue will continue, and perhaps spread to other parts of the grid. (We discuss this issue in more detail in our response to Question 11.) Also of concern is the dramatic impact that the proposed BAAL limit will have on the frequency error of the Interconnections. In WECC specifically, it has been shown that the frequency error has been steadily increasing since the start of the RBC field trial. As the drafting team has pointed out in the Background Document for this proposed standard, reliability is reduced when Interconnection frequency is moved farther from the scheduled value. In light of the fact that replacing CPS2 with the proposed BAAL limit has already been shown to have the effect of moving the frequency away from the scheduled frequency value, the adoption of proposed standard would have the overall effect of reducing reliability. We would also like to note that, under the WECC field trial, BAs that are operating with BAAL have been requested by the Reliability Coordinator to further limit their ACE due to transmission overload issues in the Interconnection caused by the operations of another BA (e.g. BA #1 is interconnected with BA#2, and BA#1's inadvertent flows cause an SOL violation at the interconnection between BA#2 and BA#3, so the RC requests BA#2 to change their operation). This should be a serious concern: A BA operating in compliance with the proposed BAL-001 reliability standard (during the RBC field trial) is causing or contributing to a violation of another reliability standard (TOP) and potentially causing another entity to be in violation.
No
No
No. As stated above in our response to Question 5, because of the significant deficiencies of Requirement 2, a BA would be able to operate in a way that could have a significant impact on reliability, for the majority of the time, without facing any penalty or sanction.
No
No. As stated above in our response to Question 5, because of the significant deficiencies of Requirement 2, a BA would be able to operate in a way that could have a significant impact on reliability, for the majority of the time, without facing any penalty or sanction.
No
No. Powerex feels the Background Document does not reference or explain any of the findings of the RBC trial discussed in Question 5 that should be of concern, i.e. BAs operating outside the BAAL limit in a cyclical manner, the detrimental impact of unscheduled flows on the grid, and the increase in frequency error.
In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for unscheduled energy flows between adjacent BAAs both to jeopardize reliability and to cause undue harm to customers on the grid. The Commission stated, at P 703, in regards to the existing framework for inadvertent energy: "However, if there is evidence that it is no longer sufficient to maintain reliability, or is allowing certain entities to lean on the grid to the detriment of other entities, the Commission has authority under FPA section 215 to direct the ERO to develop a new or modified standard to address the matter." Powerex believes that the development of the BAL-001 standard based on the current purpose statement will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impact to transmission customers on the grid. This may result in substantial curtailments to transmission customers in direct contravention of the Commission's open access transmission principles of Order 890. BAL-001 may also be in conflict with FERC Order 693 (P 397). In that order, the Commission noted that while the control performance standard metric (BAAL limit in R2) is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control. "[T]he control performance standard metric is a lagging indicator and,

as such, does not provide a good indication that necessary amounts of regulating reserve are being carried at all times." The capability to be able to meet a BA's expected intra-hour imbalances, with a significant degree of confidence, should be achieved prospectively each hour. It is not sufficient to reduce a BA's regulation to a level designed only to meet the performance standards retrospectively. Though a prospective balancing reserve requirement as contemplated in Order 693 may be missing from standards currently in place, the inherent limits in the current CPS2 are strict enough such that the need for a prospective minimum requirement is reduced. However, the relaxation of the control performance measures in BAL-001 make it imperative that the minimum reserve requirements contemplated in Order 693 are included.
The recent increase in intermittent resources, such as wind and solar generation, has increased balancing challenges due to variability in generation, driving actual generation to differ from scheduled generation. By eliminating CPS2 and replacing it with the relaxed BAAL limit, the proposed performance standard does not address the potential for a single BA to lean on the grid with deliberate unscheduled energy flows or inadvertent energy, taking any accumulated benefits for itself and possibly even jeopardizing reliability and/or harming other entities on the grid. The detrimental impacts of deliberate inadvertent flows to load customers and transmission customers on the grid could be substantial. Price signals generally drive correlated behavior across multiple market participants. Load customers could have service interrupted if multiple BAs, following market price signals, all decided to inaccurately schedule their expected hourly average generation in the same direction in the same hour, without sufficient prospective ability to restore and sustain "balance" within the BAA, if needed. Transmission customers are likely to be frequently interrupted due to unscheduled flows, if one or more BAs take advantage of the BAAL limit and deliberately rely on inadvertent energy to meet their expected BAA imbalances, as BAA imbalances can undisputedly occur without knowledge or regard to transmission availability or coordination. In order 890, FERC made it clear that it was inappropriate for generators within a BAA to "dump power on the system or lean on other generation…The tiered imbalance penalties adopted in the Final Rule generally provide a sufficient incentive not to engage is such behavior". The Commission unambiguously wanted to encourage accurate scheduling of a generator's output within a BAA. Though at the time of the 890 ruling the Commission chose not to impose similar rules preventing BAs themselves and their affiliate generators from leaning on the grid, they recognized that there was a potential for such behavior, and noted that it could take action under FPA section 215 if such deliberate inadvertent flows were degrading reliability or harming other customers. These issues have brought to the forefront the importance of the public release of BAA-specific hourly inadvertent flow data. The inadvertent flows resulting from the operations of one BAA can have a significant impact on its neighboring BAAs and the transmission customers on the grid. Powerex feels it public release of the hourly inadvertent flow data would give all entities a better understanding of the way the BAAs are operating in their region and facilitate coordinated operations to ensure the adverse impacts of inadvertent flows can be appropriately minimized. The broader wholesale electricity grid may be a valuable balancing resource for both reducing the wear and tear on dispatchable generation resources. However, it is imperative to reliability, open access transmission principles, and proper functioning wholesale energy markets, that increased utilization of the electricity grid's inherent transmission flexibility and inherent frequency flexibility be achieved within an appropriate framework. More specifically, before implementing the BAAL limits in BAL-001 and allowing BAs to use the broader electricity grid deliberately as a balancing resource, by either reducing the amount of balancing reserves dispatched, and/or potentially reducing the amount of balancing reserves carried, the following may be required: 1. Enforceable rules and processes that ensure that BAA imbalances can be immediately limited if applicable transmission flowgate limits are reached. Unscheduled energy flows resulting from BAA imbalances should clearly have the lowest priority access to transmission, behind all customers who have invested, and appropriately scheduled, to use the transmission network. 2. Minimum BA balancing reserve requirements, set prospectively, to ensure that the amount of balancing reserves carried on the broader grid are sufficient to maintain grid reliability. Reliance on performance standards, as a lagging indicator, may be insufficient to ensure reliability on a prospective basis, particularly as such performance standards become more liberal such as with the proposed BAAL limits. In Order 693, FERC noted that while the control performance standard metric like Requirement 2, is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control. FERC directed the ERO to develop a process to calculate the minimum regulating reserve for a BA, taking into account expected

load and generation variation and transactions being ramped into or out of the BA. 3. The benefits of utilizing the flexibility in the grid are appropriately allocated to all grid participants, through either BAA consolidation or BAA coordination frameworks, and FERC cost allocation oversight. Individual BAAs should not be able to lean on the grid disproportionally, hoping that there are sufficient BAs with a more conservative approach to Good Utility Practice to maintain the grid's reliability, at their customers' inequitable expense. 4. Hourly BAA imbalance data is made public (after-the-fact, in a similar manner to the way scheduled transmission usage is released on OASIS), so that NERC, the Regional Entities, BAs, impacted transmission customers, etc, can use the data to monitor the inappropriate use of unscheduled flow. Unless BAL-001 (or the framework made up by the BARC standards) includes requirements for performance in a manner that prevents an entity from deliberately leaning on the grid to gain commercial advantage, it would be inappropriate to adopt the standard in its present form.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
While we agree with these four entities comprise the four major Interconnections, the term is used scores of times in other standards. It is beyond the scope of this drafting team to redefine expectations of other standards.
Yes
Yes
Yes
Yes
Yes
Yes
No
While it is not material to the new standard, the A1 criterion is not properly stated. Under A1, ACE needed to cross zero at least once in every ten minute period of the hour and that the total non-crossings had to be less than 10 percent of all periods.
Sections 4.1.1 and 4.1.2 are unclear as to which entities are subject to complying with the standard. Further, the word "calculates" in both Sections turn these Sections into requirements rather than specifying the entities being responsible for meeting Requirements R1 and R2. Inferring from Section 4.1.3, we interpret these Sections to mean that the "Balancing Authority that provides Overlap Regulation Service to another Balancing Authority". In that case, a requirement to hold the service providing BAs responsible for calculating its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE, and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service, would be necessary. Same applies to the BAAL calculation implied in Section 4.1.3.
Group
Associated Electric Cooperative Inc, JRO00088
David Dockery
Yes
Reporting ACE definition: Replace: "the difference between the Balancing Authority's actual

interchange and its scheduled interchange plus its frequency bias obligation plus any unknown meter error" With: "control-error consideration of: interchange, frequency, and interchange-metering errors." Rationale: This simplified description may explain more without restating the equation.
Yes
No
AECI agrees with the posted for ballot Project_2010-14-1_BAL-001-1_Standard_Clean_20120604_final_rev1 copy, where "in support of interconnection frequency." is deleted.
Yes
AECI agrees with this existing and unmodified requirement.
No
AECI is fine with the wording under R2, but not strongly recommends that Attachment 2 be changed as follows: Replace: "60 Hz" or "60" With: "Fs" And reinstate: the earlier Fs definition Rationale: 1) As currently drafted, this standard penalizes BAs who are complying with directed time-error corrections, 2) This draft was only appropriate when our industry believed that time-error corrections would be retired, and 3) any concern, about time-error corrections being so large that they risk UFL first-tier margins, should be addressed by exercising smaller magnitude corrections for longer periods of time.
No
AECI concurs with the concerns expressed by SERC on behalf of smaller BAs.
Yes
Yes
Yes
No
AECI agrees with SERC comment that Attachment 1 Interconnection names should agree with those in the draft Interconnection definition.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
We question the need for the Reporting ACE definition. There is no explanation anywhere in the documentation for its need. Why is the definition of ACE not satisfactory? The definition is not even consistent with the definition of ACE. The definition of ACE uses net actual interchange and net schedule interchange. While we are sure that the Reporting ACE definition intends for these values to be net values, questions will arise why the word "net" is included in one definition and not the other in a compliance driven world. If the definition remains, we suggest striking everything after Area Control Error. Everything after this is already included in the definition of ACE to which this definition refers. The only difference between the two definitions appears to be that one is "instantaneous" and the other is a "scan rate". We think "scan rate" is nearly instantaneous and satisfies the definition particularly since it is the only way to measure ACE and considering there are other requirements (BAL-005-0.1b R8) that specify ACE only has to be calculated (which requires scanning of tie-line measurements) once every six seconds. The bottom line is that the definition does not offer additional clarity. Furthermore, we recommend that the ACE definition should be modified to include the ACE calculation from the standard. The equation really should be the definition as it is much more descriptive than the words provided in the definition.
Yes
No
We think the purpose statement should be modified to state that it is steady-state frequency that is

being controlled. Otherwise, transient frequencies are included which is problematic considering even stable swings in frequency could easily exceed the frequency bounds established in the standard.
Yes
We thank the drafting team for making it perfectly clear that only the rolling 12 month CPS1 calculation is subject to compliance and not the one month calculation.
Yes
Conceptually, we are in complete agreement with the BAAL limit. It is far superior to the CPS2 requirements. The BAAL limits consider frequency impact whereas CPS2 does not. At times, CPS2 forces a BA to move its ACE in a direction that does not support frequency. Furthermore, control for CPS2 could be turned off for 10% of the time (over a month) and a BA could still be compliant. While we agree with the requirement, some further clarification is required regarding the exclusion of one-minute samples as explained in Attachment 2. Since a violation is based on consecutive clock minutes, what should the responsible entity assume about clock-minute samples that are excluded because less than 50% of the data is available per Attachment 2? If responsible entity is exceeding a BAAL high limit for 10 minutes, then fails to record the next 8 clock-minute samples because of data unavailability, and then exceeds the same BAAL high limit for the following 13 minutes, is this a violation?
Yes
Yes
Yes
Yes
The implementation plan states that six months are required to make software changes to an EMS to accommodate the change to the standard. Is this based on the actual experience of those participating in the field trial? If not, the drafting team should reach out to the field trial participants to find out how long it took them to implement the changes. If it is, the documentation should state this clearly. In the first paragraph in the background and rationale section on page 4 of the background document, “Compliance Performance Standard” should be “Control Performance Standard”. We think the new variation on the meter error term in the ACE equation is actually more confusing than the previous meter error term. The previous term was clear that hourly integration of the instantaneous meter values was being compared to the revenue quality meters. The new term does not state this as clearly. ACE needs to be capitalized in the second paragraph of the Data Retention section. To the extent that a responsible entity is subject to periodic reporting that will demonstrate compliance, we question the need for a data retention period of one full year. No more than three months of BAAL data should be required We disagree with requiring data to be retained for up to four years. First, the current standard only required the BA to retain the data for one year. No justification has been provided for raising the bar. Second, NERC receives periodic reports for CPS1 and currently for the BAAL limits. Thus, they can retain these reports if they need them. One year is sufficient time for NERC to raise any issues or questions about the input data used in the calculation for CPS1 and the BAAL limits. If no issues have arisen to cause NERC to request data retention for a longer period within the first year, then the responsible entity should not be required to retain it. Third, retention of data beyond the three year BA audit cycle is not consistent with NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The minimum resolution for actual frequency in Attachment 2 should be removed. First, it is essentially a requirement and requirements cannot be written into attachments. Second, it raises the bar over the frequency measurement accuracy established in BAL-005-0.1b R17 without justification.
Individual
Joe Tarantino

Sacramento Municipal Utility District
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Daniel O'Hearn
Powerex Corp.
Yes
Yes
No
No, the Purpose Statement is inadequate. The purpose of the standard should be to control BAA ACE within defined limits in support of Interconnection Frequency, and to prevent BAA ACE from having a detrimental impact to other entities on the grid. In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for inadvertent energy flows between adjacent BAs to both jeopardize reliability and to cause undue harm to customers on the grid. Such inadvertent energy flows are driven by the size of each BAAs ACE, as primarily contained by CPS2 under the current BAL-001, and the new proposed BAL-001 standard. Powerex believes that the development of the BAL-001 standard based on the current purpose statement will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impact to transmission customers on the grid. This may result in substantial curtailments to transmission customers in direct contravention of the Commission's open access transmission principles.
Yes
No
No. The standard is inadequate. The requirement will allow BA's to operate in a way that could significantly increase risk to the interconnection, for up to 30 minutes, without penalty. Worse, it will allow BA's to "sawtooth": operate outside the BAAL limit for extended periods of time (up to 30 minutes), change operations for as little as one minute to bring their ACE back into the BAAL limit to reset the 30 minute clock, and then again start operating outside the BAAL limit, and do so cyclically, for extended periods. This behavior was exhibited to some extent by several BAsduring the field trial, so there should be every expectation that this type of behavior will continue, if not spread and worsen, if this new standard was put in place. In the Background Document for the standard the

drafting team pointed out that CPS2 "… allows significant hours when a Balancing Authority's ACE values are unbounded." Because R2 of the proposed standard will allow BAs to cyclically operate outside the BAAL limit as described above, the problem of BA's operating with an unbounded ACE could actually become worse under the proposed standard, not better. Powerex notes that no technical justification has been put forward as to why a BAA should be able to operate outside the BAAL limit for 30 minutes. We recommend that the drafting team consider a shorter period (e.g. 5 minutes). As well, to prevent the sawtoothing behavior, Powerex recommends that a monthly maximum be set on the number of times a BAA can exceed the BAAL limit (e.g. 5 times per month). Another concern is that the requirement will allow unlimited unscheduled flow, across interties when the actual system frequency is close to the scheduled frequency. There seems to be a disregard for the fact that unscheduled flows can have a significant detrimental impact on scheduled flows. Curtailments to scheduled flows is one of the main tools used to keep the system operating within limits during period of high unscheduled flows, effectively giving unscheduled flows priority access over the rights paid for by OATT customers (scheduled flows). For example, during the RBC trial in the West, the number of curtailments to e-tags went up dramatically as a result of unscheduled flows across path 36, as reported by the WECC Performance Workgroup in the December 2011 Quarterly Report on the RBC Field Trial. Most recently, we have seen a record number of curtailments across path 66. In 2011 there were a total of 61 Unscheduled Flow Mitigation events for Path 66 of Step 4 or higher (see the WECC USF Mitiagation Procedure). So far in 2012 there have already been 741 events of step 4 or highter. It is a serious concern that the increase in unscheduled flow across path 66 can be attributed to the the RBC field trial (i.e. the BAAL limit). If the proposed standard is approved it should be expected that this issue will continue, and perhaps spread to other parts of the grid. (We discuss this issue in more detail in our response to Question 11.) Also of concern is the dramatic impact that the proposed BAAL limit will have on the frequency error of the Interconnections. In WECC specifically, it has been shown that the frequency error has been steadily increasing since the start of the RBC field trial. As the drafting team has pointed out in the Background Document for this proposed standard, reliability is reduced when Interconnection frequency is moved farther from the scheduled value. In light of the fact that replacing CPS2 with the proposed BAAL limit has already been shown to have the effect of moving the frequency away from the scheduled frequency value, the adoption of proposed standard would have the overall effect of reducing reliability. We would also like to note that, under the WECC field trial, BAs that are operating with BAAL have been requested by the Reliability Coordinator to further limit their ACE due to transmission overload issues in the Interconnection caused by the operations of another BA (e.g. BA #1 is interconnected with BA#2, and BA#1's inadvertent flows cause an SOL violation at the interconnection between BA#2 and BA#3, so the RC requests BA#2 to change their operation). This should be a serious concern: A BA operating in compliance with the proposed BAL-001 reliability standard (during the RBC field trial) is causing or contributing to a violation of another reliability standard (TOP) and potentially causing another entity to be in violation.
No
No comment at this time.
No
No. As stated above in our response to Question 5, because of the significant deficiencies of Requirement 2, a BA would be able to operate in a way that could have a significant impact on reliability, for the majority of the time, without facing any penalty or sanction.
No
No. As stated above in our response to Question 5, because of the significant deficiencies of Requirement 2, a BA would be able to operate in a way that could have a significant impact on reliability, for the majority of the time, without facing any penalty or sanction.
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No. Powerex feels the Background Document does not reference or explain any of the findings of the RBC trial discussed in Question 5 that should be of concern, i.e. BAs operating outside the BAAL limit in a cyclical manner, the detrimental impact of unscheduled flows on the grid, and the increase in frequency error.
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existing framework for inadvertent energy: "However, if there is evidence that it is no longer sufficient to maintain reliability, or is allowing certain entities to lean on the grid to the detriment of other entities, the Commission has authority under FPA section 215 to direct the ERO to develop a new or modified standard to address the matter." Powerex believes that the development of the BAL-001 standard based on the current purpose statement will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impact to transmission customers on the grid. This may result in substantial curtailments to transmission customers in direct contravention of the Commission's open access transmission principles of Order 890. BAL-001 may also be in conflict with FERC Order 693 (P 397). In that order, the Commission noted that while the control performance standard metric (BAAL limit in R2) is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control. "[T]he control performance standard metric is a lagging indicator and, as such, does not provide a good indication that necessary amounts of regulating reserve are being carried at all times." The capability to be able to meet a BA's expected intra-hour imbalances, with a significant degree of confidence, should be achieved prospectively each hour. It is not sufficient to reduce a BA's regulation to a level designed only to meet the performance standards retrospectively. Though a prospective balancing reserve requirement as contemplated in Order 693 may be missing from standards currently in place, the inherent limits in the current CPS2 are strict enough such that the need for a prospective minimum requirement is reduced. However, the relaxation of the control performance measures in BAL-001 make it imperative that the minimum reserve requirements contemplated in Order 693 are included.
The recent increase in intermittent resources, such as wind and solar generation, has increased balancing challenges due to variability in generation, driving actual generation to differ from scheduled generation. By eliminating CPS2 and replacing it with the relaxed BAAL limit, the proposed performance standard does not address the potential for a single BA to lean on the grid with deliberate unscheduled energy flows or inadvertent energy, taking any accumulated benefits for itself and possibly even jeopardizing reliability and/or harming other entities on the grid. The detrimental impacts of deliberate inadvertent flows to load customers and transmission customers on the grid could be substantial. Price signals generally drive correlated behavior across multiple market participants. Load customers could have service interrupted if multiple BAs, following market price signals, all decided to inaccurately schedule their expected hourly average generation in the same direction in the same hour, without sufficient prospective ability to restore and sustain "balance" within the BAA, if needed. Transmission customers are likely to be frequently interrupted due to unscheduled flows, if one or more BAs take advantage of the BAAL limit and deliberately rely on inadvertent energy to meet their expected BAA imbalances, as BAA imbalances can undisputedly occur without knowledge or regard to transmission availability or coordination. In order 890, FERC made it clear that it was inappropriate for generators within a BAA to "dump power on the system or lean on other generation…The tiered imbalance penalties adopted in the Final Rule generally provide a sufficient incentive not to engage is such behavior". The Commission unambiguously wanted to encourage accurate scheduling of a generator's output within a BAA. Though at the time of the 890 ruling the Commission chose not to impose similar rules preventing BAs themselves and their affiliate generators from leaning on the grid, they recognized that there was a potential for such behavior, and noted that it could take action under FPA section 215 if such deliberate inadvertent flows were degrading reliability or harming other customers. These issues have brought to the forefront the importance of the public release of BAA-specific hourly inadvertent flow data. The inadvertent flows resulting from the operations of one BAA can have a significant impact on its neighboring BAAs and the transmission customers on the grid. Powerex feels it public release of the hourly inadvertent flow data would give all entities a better understanding of the way the BAAs are operating in their region and facilitate coordinated operations to ensure the adverse impacts of inadvertent flows can be appropriately minimized. The broader wholesale electricity grid may be a valuable balancing resource for both reducing the wear and tear on dispatchable generation resources. However, it is imperative to reliability, open access transmission principles, and proper functioning wholesale energy markets, that increased utilization of the electricity grid's inherent transmission flexibility and inherent frequency flexibility be achieved within an appropriate framework. More specifically, before implementing the BAAL limits in BAL-001 and allowing BAs to use the broader electricity grid deliberately as a balancing resource, by either reducing the amount of balancing reserves dispatched, and/or potentially reducing the amount of balancing reserves carried, the following may be required:

1. Enforceable rules and processes that ensure that BAA imbalances can be immediately limited if applicable transmission flowgate limits are reached. Unscheduled energy flows resulting from BAA imbalances should clearly have the lowest priority access to transmission, behind all customers who have invested, and appropriately scheduled, to use the transmission network. 2. Minimum BA balancing reserve requirements, set prospectively, to ensure that the amount of balancing reserves carried on the broader grid are sufficient to maintain grid reliability. Reliance on performance standards, as a lagging indicator, may be insufficient to ensure reliability on a prospective basis, particularly as such performance standards become more liberal such as with the proposed BAAL limits. In Order 693, FERC noted that while the control performance standard metric like Requirement 2, is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control. FERC directed the ERO to develop a process to calculate the minimum regulating reserve for a BA, taking into account expected load and generation variation and transactions being ramped into or out of the BA. 3. The benefits of utilizing the flexibility in the grid are appropriately allocated to all grid participants, through either BAA consolidation or BAA coordination frameworks, and FERC cost allocation oversight. Individual BAAs should not be able to lean on the grid disproportionally, hoping that there are sufficient BAs with a more conservative approach to Good Utility Practice to maintain the grid's reliability, at their customers' inequitable expense. 4. Hourly BAA imbalance data is made public (after-the-fact, in a similar manner to the way scheduled transmission usage is released on OASIS), so that NERC, the Regional Entities, BAs, impacted transmission customers, etc, can use the data to monitor the inappropriate use of unscheduled flow. Unless BAL-001 (or the framework made up by the BARC standards) includes requirements for performance in a manner that prevents an entity from deliberately leaning on the grid to gain commercial advantage, it would be inappropriate to adopt the standard in its present form.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst offers the following comment for consideration: 1. Applicability section a. RFC seeks further clarity surrounding the applicability of Balancing Authorities which do not provide Regulating Service. If a Balancing Authority does not provide Regulating Service, are they subsequently not subject to the requirements in the standard? If they are not subject to the requirements in the standard, RFC recommends removing section 4.1.3 since it is not needed as well.
Individual
Jeff Harrison
AECI
Yes
Yes
No
Delete "in support of interconnection frequency".
Yes

No
AECI would like to request a modification to Attachment 2, such that the this calculation uses the scheduled frequency and not a constant of 60.0. Such that the BAAL calculation will adjust for time error correct.
No
VRFs should be adjusted based upon the balancing authorities impact upon the interconnection.
Yes
Yes
Yes
Individual
Greg Travis
Idaho Power Company
Yes
Although WECC is pursuing a Regional Variation to include the WECC ATEC term into the reporting ACE which is needed.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
None.
None
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Based on the experience of the pilot program, this proposed standard will likely allow grid operators to maintain reliability while reducing the need for regulation reserves needed to accommodate all sources of variability on the power system. As a result, the proposed standard should be supported.
Group
Progress Energy
Jim Eckelkamp
Yes
Yes
No
It is not clear that this Standard aids in the control of frequency within defined limits, particularly for transient frequency deviations to avoid UFLS operation. Conclusive results of the BAAL field trial are not provided in the background document. If the industry is to make the move to make this change, there should be evidence provided that this action will aid in better frequency control for the Interconnections.
No
Conclusive results of the BAAL field trial are not provided in the background document. If the industry is to make the move to make the change from CPS2 to BAALs, there should be evidence provided that this action will aid in better frequency control for the Interconnections.
Absent CPS2 L10 limits, at any given time one BA has no incentive to manage its ACE and can take advantage of the regulating power of neighboring BAs who may be balancing more effectively. CPS1 remains in place, however, this is a rolling one-year average and does not provide the same incentive as CPS2. BAL-001-1 Attachment 1 proposes to define actual frequency as “FA (Actual Frequency) is the measured frequency in Hz, with minimum resolution of +/- 0.005 Hz.” This proposal includes an unreasonable resolution for frequency measurements and is unnecessary. Accuracy of frequency devices that are used in the calculation of ACE is already required by Standard BAL-005-1 Requirement 17. Further, providing this proposed required resolution on some existing industry equipment would either not be possible or would cause the total bandwidth for which the frequency can be monitored to be reduced to a level that would be unfavorable. The basis or rationale for this proposed resolution is not discussed in the background document and, and this requirement should be deleted from the Standard
Individual

Thad Ness
American Electric Power
No
The definition for the term Balancing Authority ACE Limit (BAAL) implies there is always a reliability risk for exceeding the limit, without taking into consideration relative operating conditions at the time. Merely exceeding an ACE Limit (BAAL) does not always constitute that there is an inherent reliability risk, as that would depend on the actual operating conditions and timing of the occurrence and/or normal frequency characteristics on that operating day. For example: High Frequency prior to an extreme morning load pickup with Net Scheduled Interchange out, and Low Frequency prior to nightly fall off are sometimes a more favorable reliability condition. We recommend changing the text to read “The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control’s allotted reliability deviation for required measure”. We agree with the definition of the term Reporting ACE, however, it should be noted that Balancing Authorities with membership to some Regional Power Pools use an added factor of ACE diversity component in their Reporting ACE beyond what is mentioned.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
There needs to be an understanding and appreciation of the increasing number of newly-registered market participant Generator Operators that are not from the traditional, vertically integrated utility environment, and their impact on a Balancing Authority’s ability to balance. We encourage the SDT to think of opportunities to develop appropriate requirements in order to ensure that Generator Operators can help support the objectives of balancing load and generation in a reliable manner. The background information on balancing sometimes refers back to the former “NERC Policy”, at a time when the preceding “Control Area” model applicability had different operating characteristics than today’s more granular functional model entity in terms of Balancing Authority, Generator Operator, Load Serving Entity (Demand Side Load Management), Market Operator, etc. The stated compliance applicability within the proposed Standard fails to address inherent impact of these other functional entities and variables on a Balancing Authority’s sole ability to comply with these requirements in today’s actual practice. Balancing Authorities that are part of regional energy and/or ancillary service markets may have unique challenges with respect to deployment of Balancing Authority resources. For example, the failure of following market deployment may only involve a financial market charge, however the results could have significant impact on Balancing Authority obligations.
Individual
Chris Mattson
Tacoma Power
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
MRO NSRF
WILL SMITH
No
The definition of reporting ACE is nearly identical to the current definition of ACE, but the appendix adds complexity. There should be no need for this new definition. The description of the definition in the attachment is overly prescriptive. It has a redundant and more restrictive requirement for frequency resolution than BAL-005. It also created a new term, Net Metering Error that is more prescriptive than how metering error is corrected for today.
Yes
While the NSRF agrees with these four entities comprise the four major Interconnections, the term is used scores of times in other standards. It is beyond the scope of this drafting team to redefine expectations of other standards.
Yes
Yes
While the NSRF agrees that the 12 month rolling average performance is evaluated monthly, that does not mean that substandard performance in one month should result in many months of repeat violations until that bad month rolls out the average. Non-compliance should only accrue if the BA is not under a mitigation plan and has new months of non-compliant performance.
Yes
The NSRF supports R2 as an improved approach over CPS2. While not under the purview of this drafting team, the proposed changes in BAL-003 with regard to variable bias (no floor on variable bias) opens the opportunity for gaming R2.
Yes
Yes
Yes
The drafting team may want to look at how small BAs are impacted by R2. The CPS curve for small BAs has a wider tail. The performance expectations may not be the same.
No

While it is not material to the new standard, the A1 criterion is not properly stated. Under A1, ACE needed to cross zero at least once in every ten minute period of the hour and that the total non-crossings had to be less than 10 percent of all periods.
General Comments and Observations • The drafting team changed the NERC definition of Interconnections. This term is used in many standards and may have impact on them. • The reporting ACE term that the team created seems unnecessary as ACE is already defined. It also expands on the expectations of ACE. The frequency resolution appears too tight 0.0005Hz (compared to 0.001 in BAL-005) and the new term, Net Metering Error is prescriptive on how metering error is corrected.
Group
Northeast Power Coordinating Council
Guy Zito
No
As with BAL-013-1, should “clock-minutes” be replaced with “minutes”?
Because the frequency model is simply using 3 times Epsilon 1 for trigger limits, it does not produce optimum results. The 3 times Epsilon 1 trigger limits are not calibrated to account for relay settings or frequency response. The 3 times Epsilon 1 approach has a “set it and forget it” characteristic. The alternative model would require periodic updating as relay limit settings change, the Interconnection’s frequency response changes, and the perceptions of the level of protection needed change. It also does not target a specified level of reliability. Concerns about transmission limits caused by dropping CPS 2 and the limitations in CPS 1 still haven’t been addressed. For CPS 1 data submissions, the number of one minute samples in the month becomes a new requirement. In Attachment 2 more complete guidance is needed for the treatment of a missing one minute sample when counting the time expired during a BAAL limit violation. Which of the following assumptions should be made about the missing sample: compliance, non-compliance, same state as the previous sample, same state as the next sample, or simple omission?
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
Yes
No
AZPS has not been convinced that the RBC is a better form of control then what is currently in place. Yes on VRFs Since the RBC Field Trial began the WECC average frequency deviation has been increasing. The RBC Field Trial results are not an accurate reliability assessment as not all participating Balancing Area’s Energy Management Systems have CPS1-only control capability and, thus, are not fully participating. CPS2 is designed to limit a Balancing Area’s unscheduled power flows

and does not have a frequency component – that is what CPS1 is designed to measure. The new BAAL standard will allow far more unscheduled power flows when the Interconnection frequency remains near nominal, which it predominately does. CPS2 allows a Balancing Area to be non-compliant for 72 hours (10%) each month. Under the proposed BAAL standard, a Balancing Area can be non-compliant twenty-nine minutes of each 30 minute period which is 696 hours (96%) per month. This will be taken advantage of to the detriment of reliability.
Yes
Yes
No
While "reliability issues" have not been identified by the RCs, there are other issues that need to be addressed that are not mentioned in the background document.
Yes
Yes, provides clarity but there remains disagreement with the rationale.
None noted
No comments
Individual
John Tolo
Tucson Electric Power
No
There should be an equation or formula included with the definition
Yes
Somewhat vague definition. It's more identifying the interconnections.
No
This purpose statement does not match the purpose statement in the proposed Standard.
No
There appears to be no change in CPS1 calculations or requirements so the current BAL-001-0.1a is preferred.
No
While I agree with the theory of BAAL, and the 30 minute limit, the BAAL calculation needs to address the fact that the BAAL for small BAs can be more restrictive than the current CPS2.
Yes
No
Need to address the BAAL calculation for small BAs
Yes
No
While I agree overall with the background document, there have been some transmission flow issues reported from the Western Interconnection RCs. To make a statement that there have been no reported reliability issues may not be entirely correct. I agree that BAAL has a more positive effect on interconnection frequency than does CPS2. BAAL with some sort of transmission limit might be the way to go.
no
Please note and read the WECC PWG report on RBC. Thanks to the drafting team for their efforts.
Individual
Kathleen Goodman
ISO New England Inc
No

Please see additional comments provided.
Yes
Yes
No
We believe that the frequency model and its use of 3*Epsilon for frequency trigger limits has significant shortcomings. The level of reliability targeted and achieved is a function of underfrequency relay settings, interconnection frequency response, and the size and expected outage rate of the design contingency(s) for which protection is needed. 3*Epsilon is not sensitive to these values or changes in them over time. It is not coordinated with the model in the Frequency Response Standard under development, which does address these sensitivities. We are concerned that CPS 1 alone will not address adequately the time of day short term frequency excursions observed on the Eastern Interconnection. Additionally, we continue to have reliability concerns with the BAAL limits not accounting for large ACE excursions and the possibility for an increase in transmission limit exceedences associated with such operation. We believe the Interconnection will be further exposed due to the lack of ACE bounding to somehow reflect transmission limits, and continue to believe that CPS 2 is a more reliable metric.
No
We believe that the frequency model and its use of 3*Epsilon for frequency trigger limits has significant shortcomings. The level of reliability targeted and achieved is a function of underfrequency relay settings, interconnection frequency response, and the size and expected outage rate of the design contingency(s) for which protection is needed. 3*Epsilon is not sensitive to these values or changes in them over time. It is not coordinated with the model in the Frequency Response Standard under development, which does address these sensitivities. We are concerned that CPS 1 alone will not address adequately the time of day short term frequency excursions observed on the Eastern Interconnection. Additionally, we continue to have reliability concerns with the BAAL limits not accounting for large ACE excursions and the possibility for an increase in transmission limit exceedences associated with such operation. We believe the Interconnection will be further exposed due to the lack of ACE bounding to somehow reflect transmission limits, and continue to believe that CPS 2 is a more reliable metric.
No
Given the rampant need in the industry for Requests for Interpretations, Rapid Revisions, and CANs, we believe that future Standards need to be written so that they can "stand alone" upon scrutiny.
Group
SERC OC Standards Review Group
Stuart Goza
Yes
Yes
No
Delete "in support of interconnection frequency".
Yes
This is an existing requirement and was not modified by the standard drafting team.
Yes
The SERC OC Standards Review Group is concerned that the reliability impact of violating this

requirement is proportional to the size of the balancing authority. For example, PJM, at a size of over 100,000 MW has a much more impact on reliability than SEPA, at less than 2000 MW. We do not understand how to apply VRFs consistently. This may require splitting into multiple VRFs considering the size of the BA.
No
See comments to No. 5 above.
Yes
Yes
Perhaps VSLs could be graded by the size of the entity in lieu of having multiple VRFs.
Yes
No.
Should the standard include reporting requirements to the RRO? On Attachment 1, the Interconnection names need to be revised to agree with the Interconnection as stated earlier in question 2.
Group
Southern Company
Antonio Grayson
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Western Electricity Coordinating Council
Steve Rueckert
No
BAAL 1. It is not clear what the phrase “interconnection frequency control reliability risk “means. 2. BAAL should be defined by the formula used just like ACE is defined by components used to calculate ACE Reporting ACE 1. If the existing defnition of ACE in the NERC Glossary is retired, then the proposed definition will be using the undefined term ACE which in the proposed standard is not defined. The definition cannot refer to an undefined term. If the existing definition is not retired the proposed new term and the existing term appear to be the same thing, and the new term would not be necessary. 2. The proposed standard uses a new definition Reporting ACE which is a replacement

of the current definition ACE in the BAL-001 standard. While the ACE formula has been renamed as Reporting ACE, all references to ACE in Attachment 1 of BAL-001 and in other NERC Standards have not been changed. The term ACE is used in BAL-002, BAL-003, BAL-004-WECC-1, BAL-005 and IRO standards. 3. The WECC Board of Directors recently approved a WECC Regional Variance to NERC BAL-001-0.1a that would include the Automatic Time Error Correction term in the ACE definition in the Western Interconnection. WECC is in the process of ubmitting this regional variance to NERC for NERC BOT consideration. If approved, the reporting ACE will be different for WECC. The drafting teama needs to be aware of this and take this into account. 4. WECC recommends that all of these issues can be resolve if the new term Reporting ACE is eliminated and the current ACE term is retained.
No
Texas should be replaced with ERCOT. A small portion of the state of Texas resides in the Western Interconnection. The use of the word Texas may be confusing because of this.
No
1. The phrase “to support interconnection frequency” does not add anything to the requirement and should be deleted. If a BA barely missed in one month but was compliant for the 12-month period, would that BA fail to support interconnection frequency? 2. In Attachment 1 the definitions for Net Interchange Actual and Net Interchange Schedule have been changed but they are not included in the definition section of the standard. The SDT needs to clarify if these new definitions will replace the existing approved definitions in the glossary 3. In attachment 1 the term NME in the ACE equation replaces the existing term IME. The definition itself has not changed significantly but just the acronym. WECC has Regional Standard BAL-004-WECC-1 that refers to the term IME and recommends that the SDT retain the existing term and definition of IME. 4. The attachment 1 defines Reporting ACE and essentially removing the definition for the term “ACE” but the formulas in attachment 1 still refer to ACE. WECC recommends replacing the proposed Reporting ACE with ACE which also addresses the inconsistency with all other NERC standards that refer to the term ACE. 5. It is not clear why the calculation for CPS1 was moved from the standard to the attachment. Are attachments part of the standard and if so must they go through the standards development procedure if a modification of the equation is made? Will the industry be given a chance to comment/ballot on any changes made to the formulas if they are not part of the standard. What process will be used to change content in the attachment 1 and will the industry have opportunities to comment and ballot on the changes?
No
1. The phrase “to support interconnection frequency” does not add anything to the requirement and should be deleted. 2. It is not clear why the calculations for BAAL are included in attachment 2. Are attachments part of the standard and if so must they go through the standards development procedure if a modification of the equation is made? Will the industry be given a chance to comment/ballot on any changes made to the formulas if they are not part of the standard. What process will be used to change content in the attachment 1 and will the industry have opportunities to comment and ballot on the changes?
Yes
Yes
To the extent that we believe the VSLs are appropriate for the requirements as written. However, the VSLs will potentially need to be modified if the suggested changes are implemented.
No
The background document should include the Field Trial results from all Interconnections.
1. The BAAL formula and the calculated limits are more restrictive than current standards (CPS2 and L10) for Balancing Authority with small frequency bias settings. The smallest frequency bias setting in WECC is -2 MW/0.1 Hz. The limitation of BAAL to BA of this size is substantially high. For example at 59.98 the BAALLow is calculated to be -4.62 MW compared to L10 limit which is -7.66. Under the RBC Field Trial the frequency errors and manual time error corrections have increased (WECC Report).

Hence the frequency deviates from 60 Hz more often than in the past and the smaller BAs have to excise more control to stay within their BAAL. The SDT needs to address the disparate treatment of small BAs under the proposed BAAL requirement in the standard. The Priority-based Control engineering report (PCE Report) from 2005 directed by NERC stated this issue. The report says that the proposed BAAL may require disproportionately more control from smaller BAs than larger BAs. Also in Table 7 under item 7 it is stated “PCE has verified that the proposed BAAL formulation ensures that if all BAs are within their BAAL at all times, the Interconnection frequency will not exceed FTL. Therefore, for frequency to exceed FTL, at least one BA must be outside its BAAL. However, these features are not unique to the selected BAAL formulation; many different sets of formulations would have the same properties. Additional research is necessary to determine the optimum BAAL formulation. If scheduled frequency is replaced with 60 Hz in the proposed BAAL formulation, the properties described above will no longer hold during periods of time error correction.” WECC recommends the SDT consider developing a formula that distributes the control burden fairly among BAs. 2. WECC has the following concerns with proposed BAAL requirement’s impact on transmission path loading as a result of large ACE values: a) During the field trial in WECC, an increase in Unscheduled Flow was noticed on Qualified Paths 36 and 66. In particular, during maintenance when the limit is significantly reduced high ACE values exacerbate path loading. b) The RBC field trial in the WECC was implemented in 3 distinct phases to test the impact on transmission path loading. Initially the BAAL was limited to no more than 2 times L10, in phase 2 the BAAL was limited to 4 times L10; and in phase 3 there was no cap on BAAL at 60 Hz. During Phase 3, the Reliability Coordinators (RC) reported several SOL exceedance associated with high ACE. The SOL exceedances were mitigated when RCs requested the high ACE value to be reduced to L10. The SDT must address transmission loading issues caused by high ACE.
Individual
Jay Campbell
NV Energy
No
I agree with the BAAL definition. The Reporting ACE definition is too wordy, ambiguous and confusing. To say "Scan rate values of...ACE" seems redundant. To say "measured in MW defined in BAL-001"---does one really need to define MW? Additionally, I don't see the definition. The ACE definition seems at odds with the equation on page #7. I suggest: "Balancing Authority’s Area Control Error (ACE) is the difference between the Balancing Authority’s actual interchange and its scheduled interchange plus its frequency bias multiplied by the difference between actual and scheduled frquency plus any known meter error".
Yes
No
My suggestion: "To control Interconnection frequency within defined limits."
Yes
Yes
While I generatlly agree with the intent or R2, it's too wordy. I suggest "Each Balancing Authority shall operate such that its clock-minute average Reporting ACE does not exceed, for more than 30 consecutive clock-minutes, its clock-minute BAAL [BAAL is a defined term] for the applicable Interconnection in which it operates. The BAAL equations are detailed in Attachment 2."
No
For R1, a VRF of medium seems excessive. A value, measured over a year, cannot "directly affect the electrical state or the capability of the Bulk Electric System".
Yes
Yes
Yes

I am not aware of conflicts.
No.
Group
Bonneville Power Administration
Chris Higgins
No
BPA believes that the definition is subjective and only the formula should be used for the definition.
No
BPA understands that this is an update to the existing definition, but it is not a definition. This is simply identifying the interconnections.
No
The purpose statement referenced above does not match the standard. The standard states: “To control Interconnection frequency within defined limits”. It does not include “in support of interconnection frequency”. Please clarify which one is correct.
No
BPA favors the previous version of the requirement. Referring to the attachment creates many requirements within one identified requirement without breaking them out. BPA believes there should be only one requirement within each of the identified requirements.
No
BPA disagrees with the statement in the question which says “enhance the reliability”. Referring to the attachment creates many requirements within one identified requirement without breaking the out. BPA believes there should be only one requirement within each of the identified requirements.
Yes
No
BPA does not agree with the requirements in general, and cannot support the measures.
Yes
No
The document mentions that there has been no reliability issues with the field trial. BPA and others in WECC have experienced many SOL violations due to Large ACEs. BPA disagrees with the argument that CPS2 is less reliable because you can be out of bounds for 72 hours per month. Taking the same argument to RBC, one can be out of bounds 29 minutes, back in for a minute and out of bounds for 29 minutes. This equates to 696 hours per month. BPA believes it has been demonstrated, at least in WECC, that CPS2 is more reliable. BPA has yet to determine if the decrease in reliability is worth the increase in flexibility that RBC allows.
The sub-requirements of 4.1 of the applicability section contain instructions. BPA suggests that only 4.1 and 4.1.3 (a new 4.2 created) be used instead and the rest eliminated and added as a requirement. Please refer to the WECC Reliability-based Control Field Trial Final Report July 2012 Performance Work Group Draft document. • Frequency Error • Manual Time Error Corrections • Transmission issues • Unscheduled flow events • Small BAs In the field trial, there is direction on when the RC should intervene during frequency deviations below the FTL. BPA believes this should be retained either informally or formally in the standard.
Individual
Don Schmit
NPPD

No
The elimination of CPS2 has a detrimental impact on reliability because the amount of unscheduled interchange a BA can have is not capped when frequency is in the “opposite” direction. This can lead to transmission constraints. TOPs and RCs must have a mechanism to restrict the unscheduled flows on the system due to a BA unilaterally over or under generating. I believe the old policies stated this as the intent of CPS 2 (at least it was for A2). The standard is defective as written.
Group
SPP Standards Review Group
Robert Rhodes
Yes
Yes
Yes
Yes
No
We are concerned about not being able to meet the BAAL criteria during certain contingency events exempted in BAL-002-2. For example, in the existing BAL-001-0.1a, CPS2 is a monthly average value whereby not totally covering a multiple contingency event could be exonerated at the end of the month provided control for the remainder of the month was sufficient to bring the monthly value to at least 90%. With BAAL, we only have a 30-minute window of forgiveness which could create problems, making BAAL a tighter control parameter. We would suggest at least an exemption for BAAL compliance during events whereby multiple contingencies cause the total generation loss to be greater than a BA’s or RSG’s MSSC.
Yes
Yes
Yes
Yes
The background document provided with BAL-001-1 provided valuable information regarding the history of control performance criteria and how the SDT got to where it is today with the proposed standard. What are the plans for the document? Will it become a guideline, reference document, etc? It needs to be maintained for future reference and updating.
Not aware of any conflicts.
The effective date as proposed in the draft standard is six (6) months following approval by applicable regulatory authorities. This is too short. We would suggest a 12-month window before the approved standard becomes effective. This provides the BA with time to consult with EMS vendors, design and retrofit necessary changes to existing control algorithms and testing – both acceptance testing for the AGC changes and parallel testing alongside existing AGC systems to ensure satisfactory operation. Currently, the BAs that are participating in the BAAL field trial are exempt from CPS2 compliance. During the transition from BAL-001-0.1a to BAL-001-1, there need to be exemptions extended during testing of BAAL control schemes. Currently SPP is working on a project to consolidate BAs within the

region into a single BA. The proposed completion date is scheduled for March 1, 2014. If the standard were to become effective prior to this date, considerable expense and effort would be expended needlessly once the consolidation takes place. Could SPP request a regional variance for exemption from R2 until March 1, 2014?
Individual
Karen Webb
City of Tallahassee
No
The definition for BAAL introduces a new concept of “Interconnection frequency control reliability risk”. This appears to be managing risk while the standard provides “cut and dry” limits. Suggest: “The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency deviation. This definition applies to a high limit (BAALHigh) and a low limit (BAALLow)."
Yes
No
The City of Tallahassee (TAL) is unsure of the clarity of this purpose statement. Suggest: To control individual Balancing Area ACE deviation within defined limits in support of interconnection frequency.
Yes
No
While TAL agrees with the concept of the proposed language, the change in the measurement time from BAL-001-0.1a, which was a monthly measure, to a 30-minute measure is troublesome. Each instance of exceeding 30 minutes would be a violation. This may require changes to unit responses that have not been a problem in the past due to the averaging of unit response over a month period.
No
The proposed M1 and M2 each allow for evidence in hard copy OR electronic format. Section D item 1.2 (Data Retention) seemingly excludes the acceptability of hard copy evidence. TAL suggests that the Data Retention requirement be expanded to include hard copy evidence to be consistent with M1 and M2.
No
Although TAL understands from the document's Introduction that no reliability issues have been identified in the field trial, TAL seeks additional information on the challenges encountered by the participants during the implementation and field trial. TAL also seeks greater explanation of the field trial results.
1. Effective Date: TAL questions whether six months is sufficient time for all EMS vendors to develop changes to software and for all entities to successfully implement the changes within the confines of the CIP standards, which will require multiple layers of testing outside of scheduled updates. TAL suggests 24 months. 2. Data Retention: TAL suggests a clarification to the requirement language that data retention is the longer of either (a) the data retention period defined in the standard or (b) the period since the last audit. As the proposed language reads, the need to retain evidence since the previous audit (if longer than the defined retention period) is addressed in a separate area from the defined retention period. 3. Attachment 2: Are the Epsilon 1 values expected to change?
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes

No
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Yes
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Yes
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group.
No
Yes
Yes
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Yes
No
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group.
Individual
Don Jones
Texas Reliability Entity
Yes
There is an existing definition for “Control Performance Standard” which may need to be modified or deleted. Additionally, it may be better to end the definition after the phrase “as defined in BAL-001,” as using arithmetic terms (difference and plus) may not appear to match the calculation in Attachment 1.
No
Please use “ERCOT” (not “Texas”) as the name of the Interconnection, because it does not cover the entire state of Texas. Note that “ERCOT Interconnection” is used in Attachment 1.
No
We suggest a more precise purpose statement as follows: “To control Interconnection frequency within defined limits by balancing real power supply and demand in real-time.”
Yes
No
ERCOT currently has a waiver for CPS2 compliance. With this new BAAL requirement, the waiver may no longer be needed, but this needs to be evaluated further. How will this requirement be evaluated when the BA declares an EEA? How will this requirement be evaluated if there is a generation loss event greater than the MSSC?
Yes
There is a reference to BAL-003-1 that appears misplaced in the VRF/VSL justification document (please verify).
Yes
Yes

1. For the applicability section, ERCOT, as the single BA for the entire interconnection, does not provide or receive overlap regulation service from another BA. The SDT should consider adding an additional applicability for this specific situation or re-format the section to clarify applicability to a Balancing Authority not involved in Overlap Regulation Service. 2. Is NME consistent in use of units of measure? (ACE is measure in MWs, but NME is “the meter error correction factor” representing a difference in megawatt-hours). 3. Is there a maximum excluded value for one-minute sample periods that would invalidate a CPS1 or CPS2 calculation (i.e., If 59 minutes of every hour in a month were excluded because 50% of the one-minute period data was invalid, is the CPS1/CPS2 value acceptable?)? Perhaps modify the “valid” requirements to be 50% of the time period under consideration or a similar acceptable value for the time period in question (one minute, hour, day, month…).
Individual
Nicholas L. Hall
Constellation Energy Control and Dispatch, LLC
Yes
Yes
Yes
As mentioned in later comments, the specific purpose of R2 seems to be the development of a boundary for ACE deviation, with consideration given to frequency support. Especially given the manner in which R2 attempts to control for frequency, its intent is clearly not the simple support or control of frequency.
Yes
No
While the calculation of ACE performance and its impact on frequency is a positive goal, the BAAL calculation, in its current form, does not accomplish this. Since the BAAL measure is comparing current ACE values against a calculated average frequency value, the BAAL measure inherently allows for BAAL to signal ACE corrections in the opposite direction of current frequency, and can and will penalize Balancing Authorities (through negative BAAL and CPS performance) for real-time ACE values that exceed BAAL limits, even while they are supporting current system frequency. In order to accomplish the intended goals of the requirement – to limit ACE deviations while considering their impact on frequency - , the BAAL measure needs to measure current actual ACE values against current actual frequency values at the scan rate utilized for ACE/CPS calculation. Furthermore, the trigger for when either BAALLOW or BAALHIGH is used for measure is based on actual frequency, setting up a three part disagreement in which frequency measure is used. For example, an Actual Frequency (as in Real Time, not averaged) of 60.1 is used to trigger BAALHIGH, which would then measure performance against the previous minute average frequency, which could be below 60Hz, demonstrating that the measure is not designed to accomplish its specified goals. The purpose statement also seems slightly off base. The intention of BAAL appears to provide a measurable boundary for ACE performance, with Frequency taken into consideration, rather than simply as a mechanism to support system frequency, which seems to be the specific focus of the CPS1 criteria. The purpose statement should more clearly reflect the actual intent of R2, as well as that of R1.
Yes
Yes
Yes
Yes
See comment for item 5, related to R2. If the calculation indicated for R2 is not successful in meeting the intent of the standard, then the measures would be similarly problematic.

The Applicability section of the standard takes an unusual format. 4.1.1 and 4.1.2 seem more appropriate as sub requirements for R1 and R2, respectively, than as applicability statements. If the applicability section includes Balancing Authorities and Balancing Authorities Providing Overlap Regulation Service, then 4.1.1 and 4.1.2 should move to the sub-requirements section.
Group
MISO Standards Collaborators
Marie Knox
No
The creation of a new definition, Reporting ACE, is unnecessary as Area Control Error is already a defined term. Further, the benefit to reliability from the addition of this definition is unclear; indeed, the addition of this definition may actually result in confusion regarding the appropriate measures for reliable performance. Accordingly, there does not appear to be a need for this new definition. Attachment 1 expounds upon the definition of the term Reporting ACE. This description is overly prescriptive, redundant, and more restrictive than the performance obligations provided in complementary Reliability Standards. For example, the use of frequency resolution of 0.0005Hz is more restrictive than is required under BAL-005. Further, the creation of a new term, Net Metering Error, requires utilization of a meter correction factor that is different and more restrictive than the net meter value defined and utilized today (which is an estimate). MISO further notes that the meter error utilized in this standard is referenced and utilized in other BAL standards for which no modifications are currently proposed. MISO cannot support the addition of terms and requirements that may contradict or otherwise confuse Registered Entity obligations under other, impacted Reliability Standards.
No
While MISO agrees that these four entities comprise the four major Interconnections, the term is used scores of times in other standards. It is beyond the scope of this drafting team to redefine expectations of other standards.
No
While MISO agrees with the Purpose provided in the standards, it notes that the phrase defined above is not consistent with the Purpose provided in the version of BAL-001-1 posted for comment.
No
MISO agrees that performance should be evaluated using a 12 month period evaluated on a monthly basis, but requests clarification that substandard performance in one month would not result in many months of off-normal performance. More specifically, because the inclusion of one month of off-normal performance apparently would be carried through multiple monthly calculations, the impact of that one month of off-normal performance would be retained until it “rolls out” of the time frame required for calculation of the average. Accordingly, a Balancing Authority’s performance could be impacted for a significantly longer period of time than the time period for which performance was actually impacted. Additionally, MISO notes that the language utilized in R1 indicates only the requirement to utilize a 12-month period, but does not prescribe that the time period be a “rolling twelve month” period as is indicated in the VSL section or as the “most recent consecutive twelve months” as is indicated in Attachment 1. MISO suggests that all language in the standard regarding the twelve month period be standardized to ensure that Registered Entity obligations are clear and unambiguous.
No
The proposed changes in BAL-003 with regard to variable bias (no floor on variable bias) open the opportunity for gaming R2.
Yes
Yes
Yes
No

While they are not material to the new standard, the A1 criteria are not properly stated. Under A1, ACE needed to cross zero at least once in every ten minute period of the hour and the total non-crossings had to be less than 10 percent of all periods.
MISO notes the use of cross-references and similar terms among and between reliability standards. Accordingly, terms and concepts previously utilized in BAL-001-0.1a that have been replaced, modified, or re-defined in BAL-001-1 may impact other reliability standards such as BAL-003, BAL-004, and BAL-005-0.1b. MISO notes that the use of cross-references and similar terms should be evaluated to ensure consistency amongst the reliability standards and requirements. In particular, where terms and requirements have been redefined or modified in BAL-001-1, a cross-referenced or closely related standard or requirement could be impacted by the modification to BAL-001-1. For example, BAL-005-0.1b references the “ACE equation,” which equation appears to have been replaced by an equation to calculate Reporting ACE. Additionally, the creation of a new glossary definition could result in ambiguity regarding required performance outcomes and obligations where a previous defined term had been used and is maintained in cross-referenced or closely related standards. For example, several BAL standards refer to and use ACE as a performance standard or requirement. It is unclear whether this performance obligation remains tied to raw ACE calculations or to an entity’s Reporting ACE. MISO respectfully suggests that the BARC SDT perform a comprehensive review of BAL-001-1’s impact on cross-referenced or closely related reliability standards prior to implementation.
MISO supports this standard generally and, in particular, the concept and use of BAAL in lieu of CPS2.
Individual
Alice Ireland
Xcel Energy
No
The definition of Reporting ACE appears to be overly prescriptive. The WECC has a modified ACE that is working its way through the process to make it clear that the ACE for compliance purposes would become the WECC defined ACE, not the NERC defined ACE. The drafting team needs to take this difference into account and the current draft standard does not account for that modification. The drafting team also should take this opportunity to include in the definition further clarity related to concepts such as ACE Diversity Interchange, Dynamic Schedules, Pseudo-ties and Automatic Time Error Correction.
No
Not all of Texas is in the ERCOT or Texas Interconnection, therefore the proposed change is likely to cause confusion. As an entity that has a Balancing Authority Area operating in part of the state of Texas, we can attest to the fact that there is already enough confusion in the industry related to the difference between electric service in the state of Texas and the Interconnection that operates wholly within the boundaries of Texas.
No
The purpose does not make sense. In order to make it clearer, end the sentence after the word “limits.” With this change, it would also be acceptable to add the phrase “during normal operations” after the word “limits”.
No
The last phrase “to support interconnection frequency” makes the requirement unclear. Does this language mean that frequency is not allowed to get outside of defined parameters mean that there has been a violation of the standard by an entity within the interconnection? Please delete that phrase so the requirement is clear and concise.
No
The last phrase “to support interconnection frequency” makes the requirement unclear. Please delete that phrase so the requirement is clear and concise. Additionally, the language in the requirement needs to in some way address the issue of clock minute average that are determined to be invalid do to issues with the measurement equipment, especially if the measurement equipment has an issue around the end of a 30 minute exceedance.
No

It is unclear from the language if the required data must be EMS quality or if the data can be from a data recorder such as PI. The Measure needs to be clear on this issue.
No
Xcel Energy recommends that the Background Document refer to and provide a link to the data and related evaluations that has been collected over the years of the field trial.
While not a true conflict, it appears that the design of the BAL-001-1 R2 related to RBC and the BAL-002-2 R1 are not coordinated. The drafting team should review these two requirements and determine if there is reason to modify the BAL-002 requirement to more closely match the desire to operate within a pre-determined range based on frequency under BAL-001-1 R2. Ideally, all four of the standards under the BARC SDT would be combined into a single standard to reduce the likelihood of conflicts between them during the compliance process. While separating them may make it easier to focus on the minute details of one versus the other, there is a large risk that the separation can cause conflicts based on the interpretation of one versus the interpretation of another. As an example of the type of conflict that is possible as currently structured, one could argue that Requirement R2 in BAL-001 supplant Requirement R1 in BAL-002 or is Requirement R1 of BAL-002 the superior requirement.
Individual
Brett Holland
KCP&L
The proposed BAAL measure in replacement of the current CPS2 removes a performance measure that is independent of the rest of the interconnection performance. The current CPS2 is based on interconnection statistical performance and provides an entity with a measure that is an indication of how well an entity is balanced with energy resources to load obligations. The proposed BAAL measure is very close in concept to the measure for the current CPS1 and has a similar effect. As the interconnection frequency moves away from 60 Hz the BAAL boundaries shrink and can shrink to levels that are lower than metering accuracies inherent in control systems and the normal variations of ACE that can occur. The current CPS1 ties an entities control performance to rest of the interconnection as it is a function of actual system frequency. The current CPS2 reflects an entities independent performance for maintaining an acceptable balance of load to energy resources. It is important for an entity to have some measure of its own performance apart from the performance of the interconnection. There may be a reliability need to "tighten" the performance metrics around what constitutes good and acceptable "balance"of load obligations and energy resources, but it is important to maintain a metric that reflects an entities performance apart from the rest of the interconnection.
Individual
Laura Lee
Duke Energy
No
Duke Energy agrees with the Balancing Authority ACE Limit definition. Duke Energy does not support the use of the new term “Reporting ACE” as we are unaware of any issues to date created by the current defined term in the standard. It is understood that the “instantaneous” value of ACE is the current scan, as that is the ACE made available to the operator in real-time. The Reporting ACE

definition adds unnecessary confusion and should therefore not be developed. ACE should be substituted in any instance where “Reporting ACE” is used in these standards. If the drafting team moves forward with its proposal to use “Reporting ACE”, Duke Energy believes that the Standards and supporting documentation need to clarify that any reference to “clock-minute ACE” means the clock-minute average of the Reporting ACE.
Yes
Though this definition appears appropriate, if the “Texas” Interconnection includes operation of areas outside of the state of Texas, another name should be considered.
No
The Purpose Statement in the draft differs from what is presented in question 3 and states “To control Interconnection frequency within defined limits”. The purpose stated in this question is preferable, with capitalization of the second use of interconnection. Add “in support of Interconnection frequency” to the proposed Purpose Statement. Additionally, the Background document uses the term “predefined limits” which is a more accurate description.
Yes
Yes
See comment to question 1 on the use of Reporting ACE.
Yes
Yes
Yes
Yes
The document provides sufficient clarity as to the development of the standard. There is no value added to the document, however, with the inclusion of the “Historical Significance” section going back to 1973, A1-A2 Control Performance Criteria, then leading up to 1996 describing the NERC Policy CPS1, CPS2, and DCS. The SDT simply needs to define CPS1 and CPS2 and their rationale for the development of the standard. On page 5 of the document, the SDT left out the word “Standard” between Performance and 2 in the first paragraph under the “Background and Rationale” section. “Significant hours” is not a good description for the 72 hours per month a BA’s ACE can be outside its L10 as it is used in the last sentence of the document on page 6. It should be changed to something along the lines of, “....allows for a Balancing Authority’s ACE value to be unbounded for a specific amount of time during a calendar month.”
It could be interpreted that the language in R5 of EOP-002-3 conflicts with the CPS1 and BAAL standards. EOP-002-3 R5 includes the sentences, “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.” As operation in support of Interconnection frequency under CPS1 and BAAL allows for support beyond that supplied by frequency bias action, Duke Energy believes that the sentences should be taken out of EOP-002-3 R5, which were never intended to be applicable to the deficient Balancing Authority for which the standard applies. Conforming changes will also need to be made to EOP-002-3 R6 which references “Control Performance and Disturbance Control Standards”. It could be interpreted from the language in R6 of EOP-002-3, that a Balancing Authority is considered in an emergency condition and should be implementing its emergency plan if it is not capable of complying at any time to the CPS1, CPS2, BAAL, or DCS measures. In a multiple-BA Interconnection, the bounds of CPS1 and BAAL represent each BA’s share of responsibility in maintaining frequency within defined bounds - to the extent that Interconnection frequency remains within acceptable limits, non-compliance in a general sense is more of an equity concern, than a reliability issue rising to the level requiring actions up to an including the shedding of firm load to remain compliant. Under what circumstances should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to the “Control Performance and Disturbance Control Standards”?
Duke Energy does not believe that the Applicability section of the Standard should contain or clarify

requirements of entities to the extent presented in the draft BAL-001-1. As the current definition of Overlap Regulation Service states “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”, Duke Energy would propose that Applicability should be assigned to “Balancing Authority not receiving Overlap Regulation Service”. There appear to be incorrect references in the VRF/VSL document. The justification for R1 references BAL-003-1 for Guideline 2 instead of BAL-001-1. The justification for R2 also references BAL-003-1 for Guideline The Compliance Enforcement Authority Section language is not the same as that specified in the Background Information for Quality Reviews dated February 2012.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-001-1 – Real Power Balancing Control Performance

Please **do not** use this form to submit comments on the proposed revisions to BAL-001-1 Real Power Balancing Control Performance. Comments must be submitted on the electronic comment form by 8 p.m. **July 3, 2012**. If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

BAL-001-1 Real Power Balancing Control Performance

Background Information:

Control Performance Standard 1 (CPS1) has been retained, and details for calculating CPS1 are included in Attachment 1. Calculation of Reporting Area Control Error (Reporting ACE) has been clarified, and details for calculating Reporting ACE are also included in Attachment 1. The Balancing Authority ACE Limit (BAAL), an interconnection frequency and Balancing Authority ACE measurement, is included in this standard as Requirement 2 and replaces Control Performance Standard 2 (CPS2). Details for the calculation of BAAL are included in Attachment 2.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L10. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive ten minute period was within the L10 bound 90 percent of all 10 minute periods over a one month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency.

BAAL is defined by two equations, BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than 60 hertz and BAAL high is for Interconnection frequency values greater than 60 hertz. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from 60 hertz, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently there are 13 Balancing Authorities participating in the Eastern Interconnection, 26 Balancing Authorities participating in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all interconnections continue to monitor the performance of those participating Balancing Authorities and

provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The BARC SDT has developed two new terms to be used with this standard.**

   Balancing Authority ACE Limit (BAAL):

   The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit (BAALHigh) and a low limit (BAALLow).

   Reporting ACE:

   The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW as defined in BAL-001 which includes the difference between the Balancing Authority's actual interchange and its scheduled interchange plus its frequency bias obligation plus any known meter error.

   Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

2. **The SDT has modified the definition for the term Interconnection. The new definition is shown below in redline to show the changes proposed.**

   Interconnection:

   When capitalized, any one of the four~~three~~ major electric system networks in North America: Eastern, Western, Texas and Quebec~~ERCOT~~.

   Do you agree with this new definition for Interconnection? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

3. **The proposed Purpose Statement for the draft standard is:**

To control Interconnection frequency within defined limits in support of interconnection frequency.

Do you agree with this purpose statement? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments:

4. **The BARC SDT has developed Requirement R1 to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to supports its Interconnection's frequency over a rolling one year period.**

   R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly, to support interconnection frequency.

   Do you agree with this Requirement? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

5. **The BARC SDT has developed Requirement R2 to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.**

   R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support interconnection frequency.

   Do you agree with this Requirement? If not, please explain in the comment area below.

   ☐ Yes

   ☒ No

   Comments: In HQT's fielt trial, frequency limits were defined from 59.9 Hz to 60.1Hz. The proposed methodology in Appendix 2 does not reflect those values since the 3*epsilon methodology leads to 59.937 Hz to 60.063 Hz frequency limits.

6. **The BARC SDT has developed VRFs for the proposed Requirements within this standard. Do you agree that these VRFs are appropriately set? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

Comments:

7. **The BARC SDT has developed Measures for the proposed Requirements within this standard. Do you agree with the proposed Measures in this standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

8. **The BARC SDT has developed VSLs for the proposed Requirements within this standard. Do you agree with these VSLs? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

9. **The BARC SDT has developed a document "BAL-001-1 Real Power Balancing Control Standard Background Document" which provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

10. **If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.**

Comments:

11. **Do you have any other comment on BAL-001-1, not expressed in the questions above, for the BARC SDT?**

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-001-1 – Real Power Balancing Control Performance

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BAL-001-1 Real Power Balancing Control Performance

Background Information:

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As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently there are 13 Balancing Authorities participating in the Eastern Interconnection, 26 Balancing Authorities participating in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all interconnections continue to monitor the performance of those participating Balancing Authorities and

provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The BARC SDT has developed two new terms to be used with this standard.**

   Balancing Authority ACE Limit (BAAL):

   The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit (BAALHigh) and a low limit (BAALLow).

   Reporting ACE:

   The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW as defined in BAL-001 which includes the difference between the Balancing Authority's actual interchange and its scheduled interchange plus its frequency bias obligation plus any known meter error.

   Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.

   ☐ Yes

   ☒ No

   Comments:
   In attachment 1, the F_A (Actual Frequency) term is defined and indicates a resolution of ±0.0005 Hz. This should be changed to align with the BAL-005-0.1b R17 that indicates a frequency resolution ≤ 0.001 Hz.

   Additionally, the acronym "ACE" is defined in the Reporting ACE definition but not in the BAAL definition. It should be defined at each usage or at none.

2. **The SDT has modified the definition for the term Interconnection. The new definition is shown below in redline to show the changes proposed.**

   Interconnection:

   When capitalized, any one of the four~~three~~ major electric system networks in North America: Eastern, Western, Texas and Quebec~~ERCOT~~.

Do you agree with this new definition for Interconnection? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments:

3. **The proposed Purpose Statement for the draft standard is:**

   To control Interconnection frequency within defined limits in support of interconnection frequency.

   Do you agree with this purpose statement? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

4. **The BARC SDT has developed Requirement R1 to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to supports its Interconnection's frequency over a rolling one year period.**

   R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly, to support interconnection frequency.

   Do you agree with this Requirement? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

   Although Manitoba Hydro agrees with this Requirement, we suggest the following clarifications to the Requirement wording. The words 'as calculated in Attachment 1' should be replaced with 'calculated in accordance with Attachment 1' for clarity. The reference to 'it' should specify the Balancing Authority for clarity.

5. **The BARC SDT has developed Requirement R2 to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.**

   R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support interconnection frequency.

Do you agree with this Requirement? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments:

The reference to 'it' should specify the Balancing Authority for clarity.

6. **The BARC SDT has developed VRFs for the proposed Requirements within this standard. Do you agree that these VRFs are appropriately set? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

7. **The BARC SDT has developed Measures for the proposed Requirements within this standard. Do you agree with the proposed Measures in this standard? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

8. **The BARC SDT has developed VSLs for the proposed Requirements within this standard. Do you agree with these VSLs? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

9. **The BARC SDT has developed a document "BAL-001-1 Real Power Balancing Control Standard Background Document" which provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

10. **If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.**

Comments:
In attachment 1, the F_A (Actual Frequency) term is defined and indicates a resolution of ±0.0005 Hz. This should be changed to align with the BAL-005-0.1b R17 that indicates a frequency resolution ≤ 0.001 Hz.

11. Do you have any other comment on BAL-001-1, not expressed in the questions above, for the BARC SDT?

Comments:

Under Applicability Section 4.1.1, the term “CPS1” is used but the acronym is not defined until R1. It should be defined at the first use.

Under the Effective Date Section, the effective date language has a few issues in its drafting. It would be clearer to use the word ‘following’ as opposed to the word ‘beyond’ (and this would also be more consistent with the drafting of similar sections in other standards). The words ‘the standard becomes effective’ in the third line are not needed. The words ‘made pursuant to the laws applicable to such ERO governmental authorities’ may not be appropriate. It’s not the laws applicable to the governmental authorities that are relevant, but the laws applicable to the entity itself. We would suggest wording like ‘or as otherwise made effective pursuant to the laws applicable to the Balancing Authority’. Also, ERO is not defined.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-001-1 – Real Power Balancing Control Performance

Please **do not** use this form to submit comments on the proposed revisions to BAL-001-1 Real Power Balancing Control Performance. Comments must be submitted on the electronic comment form by 8 p.m. **July 3, 2012**. If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

BAL-001-1 Real Power Balancing Control Performance

Background Information:

Control Performance Standard 1 (CPS1) has been retained, and details for calculating CPS1 are included in Attachment 1. Calculation of Reporting Area Control Error (Reporting ACE) has been clarified, and details for calculating Reporting ACE are also included in Attachment 1. The Balancing Authority ACE Limit (BAAL), an interconnection frequency and Balancing Authority ACE measurement, is included in this standard as Requirement 2 and replaces Control Performance Standard 2 (CPS2). Details for the calculation of BAAL are included in Attachment 2.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L10. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive ten minute period was within the L10 bound 90 percent of all 10 minute periods over a one month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency.

BAAL is defined by two equations, BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than 60 hertz and BAAL high is for Interconnection frequency values greater than 60 hertz. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from 60 hertz, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently there are 13 Balancing Authorities participating in the Eastern Interconnection, 26 Balancing Authorities participating in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all interconnections continue to monitor the performance of those participating Balancing Authorities and

provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The BARC SDT has developed two new terms to be used with this standard.**

   Balancing Authority ACE Limit (BAAL):

   The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit (BAALHigh) and a low limit (BAALLow).

   Reporting ACE:

   The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW as defined in BAL-001 which includes the difference between the Balancing Authority's actual interchange and its scheduled interchange plus its frequency bias obligation plus any known meter error.

   Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

2. **The SDT has modified the definition for the term Interconnection. The new definition is shown below in redline to show the changes proposed.**

   Interconnection:

   When capitalized, any one of the four~~three~~ major electric system networks in North America: Eastern, Western, Texas and Quebec~~ERCOT~~.

   Do you agree with this new definition for Interconnection? If not, please explain in the comment area below.

   ☒ Yes

   ☐ No

   Comments:

3. **The proposed Purpose Statement for the draft standard is:**

To control Interconnection frequency within defined limits in support of interconnection frequency.

Do you agree with this purpose statement? If not, please explain in the comment area below.

☐ Yes

☒ No

Comments: **Delete "in support of interconnection frequency".**

4. **The BARC SDT has developed Requirement R1 to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to supports its Interconnection's frequency over a rolling one year period.**

R1. Each Balancing Authority shall operate such that the Balancing Authority's Control Performance Standard 1 (CPS1), as calculated in Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly, to support interconnection frequency.

Do you agree with this Requirement? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments: **This is an existing requirement and was not modified by the standard drafting team.**

5. **The BARC SDT has developed Requirement R2 to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.**

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed for more than 30 consecutive clock-minutes its clock-minute Balancing Authority ACE Limit (BAAL), as calculated in Attachment 2, for the applicable Interconnection in which it operates to support interconnection frequency.

Do you agree with this Requirement? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments: **The SERC OC Standards Review Group is concerned that the reliability impact of violating this requirement is proportional to the size of the balancing authority. For example, PJM, at a size of over 100,000 MW has a much more impact on reliability than SEPA, at less than 2000 MW. We do not understand how to apply VRFs consistently. This may require splitting into multiple VRFs considering the size of the BA.**

6. **The BARC SDT has developed VRFs for the proposed Requirements within this standard. Do you agree that these VRFs are appropriately set? If not, please explain in the comment area below.**

☐ Yes

☒ No

Comments: **See comments to No. 5 above.**

7. **The BARC SDT has developed Measures for the proposed Requirements within this standard. Do you agree with the proposed Measures in this standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

8. **The BARC SDT has developed VSLs for the proposed Requirements within this standard. Do you agree with these VSLs? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: **Perhaps VSLs could be graded by the size of the entity in lieu of having multiple VRFs.**

9. **The BARC SDT has developed a document "BAL-001-1 Real Power Balancing Control Standard Background Document" which provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

10. **If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.**

Comments: **No**

11. **Do you have any other comment on BAL-001-1, not expressed in the questions above, for the BARC SDT?**

Comments: **Should the standard include reporting requirements to the RRO? On Attachment 1, the Interconnection names need to be revised to agree with the Interconnection as stated earlier in question 2.**

"The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."

Members participating in the development of comments:

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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:

1. The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal comment period on May 15, 2007.
2. A revised SAR for Project 2007-05, Reliability Based Controls, was posted for a second 30-day formal comment period on September 10, 2007.
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Anticipated Actions	Anticipated Date
1. Second posting	March/April 2013
2. Initial Ballot	April 2013
3. Recirculation Ballot	October 2013
4. NERC BOT adoption.	November 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error plus Automatic Time Error Correction (ATEC – If operating in the Western Interconnection and in the ATEC mode).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western interconnection.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- $Y = B / B_S$.
- H = Number of Hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B * \Delta TE/6)$
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} – TE_{begin\ hour} – TD_{adj} – (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

  $$\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}} = \text{last period's } \mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area net interchange schedules and all net interchange actual values is equal to zero at all times.
3. The use of a common scheduled frequency F_S for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**

2. **Number:** **BAL-001-2**

3. **Purpose:** To control Interconnection frequency within defined limits.

4. **Applicability:**

 4.1. Balancing Authority

 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

 4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in period during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Regulation Reserve Sharing Group.

 4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

 5.1. First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its compliance enforcement authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The compliance enforcement authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock minutes or less.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock minutes or less.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock minutes or less.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8,	BOT Approval	New

	2005		
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent consecutive 12-calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent consecutive 12-calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting 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 Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock minute.

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

And,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where**:**

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)

$BAAL_{High}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_S - $3\varepsilon 1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as F_S + $3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

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- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period

data is available or valid, then that one-minute interval is excluded from the BAAL calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Regulation Service.

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Anticipated Actions	Anticipated Date
1. Second posting	March/April 2013
2. Initial Ballot	April 2013
3. Recirculation Ballot	October 2013
4. NERC BOT adoption.	November 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply ~~operating~~the regulating -reserve required for ~~each~~all ~~member Balancing~~member Balancing Authorit~~y~~ies to -use in meeting ~~the~~applicable regulating standards~~ requirements associated with Control Performance Standard 1~~.

Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of ~~all~~ the Balancing Authorities participating in~~that make up~~ the Regulation Reserve Sharing Group at the time of measurement.~~Balancing Authority ACE Limit (BAAL): The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit ($BAAL_{High}$) and a low limit ($BAAL_{Low}$).~~

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, ~~as defined in BAL-001,~~ which includes the difference between the Balancing Authority's net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error plus Automatic Time Error Correction (ATEC – If operating in the Western Interconnection and in the ATEC mode).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western interconnection.

$I_{ATEC} = \dfrac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- $Y = B / B_S$.
- H = Number of Hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1\text{-}Y) * (II_{actual} - B * \Delta TE/6)$
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

$$PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\ peak} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area net interchange schedules and all net interchange actual values is equal to zero at all times.
3. The use of a common scheduled frequency F_S for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT~~Texas~~ and Quebec.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** ~~BAL-001-1~~BAL-001-2
3. **Purpose:** To control Interconnection frequency within defined limits.
4. **Applicability:**

4.1. Balancing Authority

4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in period during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Regulation Reserve Sharing Group.

4.2. Regulation Reserve Sharing Group

~~**4.1.1**A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE, and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.~~

~~A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Regulation Service.~~

~~**4.1.2** A Balancing Authority receiving Overlap Regulation Service is not subject to CPS1 or BAAL compliance evaluation.~~

5. **(Proposed) Effective Date:**

5.1. First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity~~Each Balancing Authority~~ shall operate such that the ~~Balancing Authority's~~ Control Performance Standard 1 (CPS1), ~~as applicable and as~~ calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly~~, to support Interconnection frequency~~. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes ~~its clock-minute Balancing Authority ACE Limit (BAAL)~~, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority~~it or Regulation Reserve Sharing Group~~ operates ~~to support Interconnection frequency~~. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity~~Each Balancing Authority~~ shall provide evidence, upon request,~~;~~ such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request,~~;~~ such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~The regional entity is the compliance enforcement authority, except where the responsible entity works for the regional entity. Where the responsible entity works for the regional entity, the regional entity will establish an agreement with the ERO, or another entity approved by the ERO and FERC (i.e., another regional entity), to be responsible for compliance enforcement.~~

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity ~~Balancing Authority~~ shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its compliance enforcement authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE~~ce~~ is calculated for the current year, plus three previous calendar years.

If a Responsible Entity ~~Balancing Authority~~ is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The compliance enforcement authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the R~~R~~esponsible Entity,~~'s or thea Balancing Authority's,~~ ~~area value of CPS1,~~ on a rolling 12-month basis, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, on a rolling 12-month basis, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority	The Balancing Authority	The Balancing Authority	The Balancing Authority exceeded its clock-

	exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for~~less than or equal to~~ 45 consecutive clock minutes or less.	exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for~~less than or equal to~~ 60 consecutive clock minutes or less.	exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for ~~less than or equal to~~ 75 consecutive clock minutes or less.	minute BAAL for greater than 75 consecutive clock-minutes.

E. Regional Variances

None.

F. Associated Documents

~~BAL-001-1~~BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

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

0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent consecutive ~~over a~~ 12-calendar months~~-period~~, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-}month}}{(\varepsilon 1_I)^2}$$

~~where~~Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

The rating index $CF_{12\text{-}month}$ is derived from the most recent consecutive 12-calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.

~~Reporting ACE is calculated as follows:~~

$$\cancel{\textbf{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}}$$

~~Where:~~

~~**NI_A (Net Interchange Actual)** is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.~~

~~**NI_S (Net Interchange Schedule)** is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and~~

~~taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.~~

~~**B (Frequency Bias Setting)** is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.~~

~~**10** is the constant factor that converts the frequency bias setting units to MW/Hz.~~

~~**F_A (Actual Frequency)** is the measured frequency in Hz, with minimum resolution of +/- 0.0005 Hz.~~

~~**F_S (Scheduled Frequency)** is 60.0 Hz, except during a time correction.~~

~~**$_{NME}$ (Net Meter Error)** is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NI_A) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).~~

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock minute.

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

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

~~and~~And,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

~~A Balancing Authority receiving Overlap Regulation Service is not subject to CPS1compliance evaluation.~~

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency~~60 Hz~~, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency~~60 Hz~~, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

$$\cancel{BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - 60\right)\right) \times \frac{\left(FTL_{Low} - 60\right)}{\left(F_A - 60\right)}}$$

When actual frequency is greater than Scheduled Frequency~~60 Hz~~, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

$$\cancel{BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - 60\right)\right) \times \frac{\left(FTL_{High} - 60\right)}{\left(F_A - 60\right)}}$$

Where**:**

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)

$BAAL_{High}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz~~, with a minimum resolution of +/- 0.0005 Hz~~.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_S ~~60~~ - 3$\varepsilon 1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as F_S~~60~~ + 3$\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz

- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the BAAL calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Regulation Service.

~~A Balancing Authority receiving Overlap Regulation Service is not subject to BAAL compliance evaluation.~~

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-2 – Real Power Balancing Control Performance

Approvals Required
BAL-001-2 – Real Power Balancing Control Performance

Prerequisite Approvals
None

Revisions to Glossary Terms
The following definitions shall become effective when BAL-001-2 becomes effective:

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error.

Reporting ACE is calculated as follows:

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

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area net interchange schedules and all net interchange actual values is equal to zero at all times.
3. The use of a common scheduled frequency FS for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

The existing definition of Interconnection should be retired at midnight of the day immediately prior to the effective date of BAL-001-2, in the jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Regulation Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-2 shall become effective as follows:

> First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-001-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-2a — Reliability Coordination — Current Day Operations

IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-~~1~~ 2 – Real Power Balancing Control Performance

Approvals Required

BAL-001-2~~1~~ – Real Power Balancing Control Performance

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-001-2~~1~~ becomes effective:

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

~~**Balancing Authority ACE Limit (BAAL):** The limit beyond which a Balancing Authority contributes more than its share of Interconnection frequency control reliability risk. This definition applies to a high limit (BAAL~~$_{High}$~~) and a low limit (BAAL~~$_{Low}$~~).~~

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, ~~as defined in BAL-001,~~ which includes the difference between the Balancing Authority's net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error.

Reporting ACE is calculated as follows:

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

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those tie lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area net interchange schedules and all net interchange actual values is equal to zero at all times.
3. The use of a common scheduled frequency FS for all areas at all times.
4. ~~1.~~4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT~~Texas~~ and Quebec.

The existing definition of Interconnection should be retired at midnight of the day immediately prior to the effective date of BAL-001-~~1~~2, in the jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Regulation Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-~~1~~ 2 shall become effective as follows:

First day of the first calendar quarter that is six 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 the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-001-~~1~~ 2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-~~1~~ 2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-2a — Reliability Coordination — Current Day Operations

IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control
BAL-001-2 – Real Power Balancing Control Performance

Please **do not** use this form to submit comments on the proposed revisions to BAL-001-2 Real Power Balancing Control Performance. Comments must be submitted on the electronic comment form by 8 p.m. ET on **April 25, 2013**.

If you have questions please contact Darrel Richardson (via email) or by telephone at (609) 613-1848.

Background Information:

Control Performance Standard 1 (CPS1) has been retained, and details for calculating CPS1 are included in Attachment 1. Calculation of Reporting Area Control Error (Reporting ACE) has been clarified, and details for calculating Reporting ACE are also included in Attachment 1. The Balancing Authority ACE Limit (BAAL), an interconnection frequency and Balancing Authority ACE measurement, is included in this standard as Requirement 2 and replaces Control Performance Standard 2 (CPS2). Details for the calculation of BAAL are included in Attachment 2.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L10. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive ten minute period was within the L10 bound 90 percent of all 10 minute periods over a one month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency.

BAAL is defined by two equations, BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than 60 hertz and BAAL high is for Interconnection frequency values greater than 60 hertz. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from 60 hertz, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently there are 13 Balancing Authorities participating in the Eastern Interconnection, 26 Balancing Authorities participating in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all interconnections continue to monitor the performance of those participating Balancing Authorities and provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator.

Questions

You do not have to answer all questions. Enter all comments in plain text format. Bullets, numbers, and special formatting will not be retained. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. **The BARC SDT has developed two new terms to be used with this standard.**

   Regulation Reserve Sharing Group

   A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

   Regulation Reserve Sharing Group Reporting ACE

   At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

   Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

2. **If you are not in support of this draft standard, what modifications do you believe need to be made in order for you to support the standard? Please list the issues and your proposed solution to them.**

   Comments:

3. **If you have any other comments on BAL-001-2 that you haven’t already mentioned above, please provide them here:**

   Comments:

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BAL-001-2 – Real Power Balancing Control Performance Standard Background Document

February 2013

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Table of Contents

Introduction

This document provides background on the development, testing, and implementation of BAL-001-2 - Real Power Balancing Control Standard. The intent is to explain the rationale and considerations for the requirements and their associated compliance information.

The original work for this standard was done by the Balancing Authority Controls standard drafting team, which later joined with the Reliability-based Control Standard drafting team. These combined teams were renamed Balance Authority Reliability-based Control standard drafting team (BARC SDT).

The purpose of proposed Standard BAL-001-2 is to maintain Interconnection frequency within predefined frequency limits. This draft standard defines Balancing Authority ACE Limit (BAAL), and required the Balancing Authority (BA) to balance its resources and demand in Real-time so that its clock-minute average of its Area Control Error (ACE) does not exceed its BAAL for more than 30 consecutive clock-minutes.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently participating in the field trial are 13 Balancing Authorities in the Eastern Interconnection, 26 Balancing Authorities in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all Interconnections continue to monitor the performance of those participating Balancing Authorities and provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator. The Western Interconnection has experienced changes during the field trial with potential degradation to transmission; however, no explicit linkage has been determined between the field trial and these degradations. For further information on the results of the Western Interconnection, please refer to the WECC Reliability-based Control Field Trial Report.

Historical Significance

A1-A2 Control Performance Policy was implemented in 1973 as:

- A1 required the Balancing Authority's ACE to return to zero within 10 minutes of previous zero.
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- A1-A2 had three main short comings:
  - Lack of theoretical justification
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  - Independent of Interconnection frequency

In 1996, a new NERC policy was approved which used CPS1, CPS2, and DCS.

CPS1is a:

- Statistical measure of ACE variability
- Measure of ACE in combination with the Interconnection's frequency error
- Based on an equation derived from frequency-based statistical theory

CPS2 is:

- Designed to limit a Control Area's (now known as a Balancing Authority) unscheduled power flows
- Similar to the old A2 criteria

The proposed BAL-001-2 retains CPS1, but proposes a new measure BAAL to replace CPS2. Currently CPS2:

- Does not have a frequency component.
- CPS2 many times give the Balancing Authority the indication to move their ACE opposite to what will help frequency.
- Only requires Balancing Authorities to comply 90 percent of the time as a minimum.

Background and Rationale by Requirement

Requirement 1

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly.

Background and Rationale

Requirement R1 is not a new requirement. It is a restatement of the current BAL-001-0.1a Requirement R1 with its equation and explanation of its individual components moved to an attachment, Attachment 1 - Equations Supporting Requirement R1 and Measure M1. This requirement is commonly referred to as Control Performance Standard 1 (CPS1). R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to support its Interconnection's frequency over a rolling one-year period.

CPS1 is a measure of a Balancing Authority's control performance as it relates to its generation, Load management, and Interconnection frequency when measured in one-minute averages over a rolling one-year period. If all Balancing Authorities on an Interconnection are compliant with the CPS1 measure, then the Interconnection will have a root mean square (RMS) frequency error less than the Interconnection's Epsilon 1.

A Balancing Authority reports its CPS1 value to its regional entity each month. This monthly value provides trending data to the Balancing Authority, NERC resources subcommittee, and others as needed to detect changes that may indicate poor control on behalf of the Balancing Authority. Requirement R1 remains unchanged, although the wording of the requirement was modified to provide clarity.

Requirement 2

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

Background and Rationale

Requirement R2 is a new requirement intended to replace existing BAL-001-0.1a Requirement R2, commonly referred to as Control Performance Standard 2 (CPS2). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

The Balancing Authority ACE Limits (BAAL) are unique for each Balancing Authority and provide dynamic limits for its Area Control Error (ACE) value limit as a function of its Interconnection frequency. BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz. The FTL is equal to Scheduled Frequency, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square (RMS) targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its FTL. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its FTL limits.

BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than Scheduled Frequency, and BAAL high is for Interconnection frequency values greater than Scheduled Frequency. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from Scheduled Frequency, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive 10-minute period was within the L_{10} bound 90 percent of all 10-minute periods over a one-month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency. For example, the Balancing Authority may be increasing or decreasing generation to meet its CPS2 bounds, even if this is a direction that reduces reliability by moving Interconnection frequency farther from its scheduled value. CPS2 allows a Balancing Authority to be outside its ACE bounds 10 percent of the time. There are 72 hours per month that a Balancing Authority's ACE can be outside its L_{10} limits and be compliant with CPS2.

In summary, the proposed BAAL requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an individual Balancing Authority's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This requirement replaces and improves upon CPS2, which is not dynamic, is not based on Interconnection frequency, and allows for a Balancing Authority's ACE value to be unbounded for a specific amount of time during a calendar month.

Change From 60Hz to Scheduled Frequency

The base frequency for the determination of BAAL was changed from 60 Hz to Scheduled Frequency, $\mathbf{F_S}$. This change was made to resolve a long-standing problem with the requirement as first presented by the Balancing Resources and Demand Standard Drafting Team. The following presents information about the reason for the initial choice of 60 Hz and the need to change this value to Scheduled Frequency.

The initial BAAL equations were developed upon the assumption that the Frequency Trigger Limit (FTL) should be based upon Scheduled Frequency as shown in this draft of the standard. During initial development of values for the FTL the BRD SDT used a deterministic method for the selection of FTL based upon the Under-Frequency Relay Limit (UFRL) of an interconnection. Since the Under-Frequency Relay Limit of the interconnection is fixed the SDT chose to use a fixed value of starting frequency that would maintain a fixed frequency difference between the FTL and the UFRL. Therefore, the BRD SDT chose to base BAAL on a starting frequency of 60 Hz under the assumption that if the UFRL did not change then the FTL and base frequency should not change. The BAAL Field Trial was started using these values.

Shortly after the field trial started, directed research supporting the selection of the FTL for the Eastern Interconnection was completed. Unfortunately, the methods used to support the selection of an FTL for the Eastern Interconnection could not be repeated successfully for the other interconnections. Included in the final report was a recommendation that a multiple of 3 to 4 times the ε_1 for the interconnection could provide an acceptable alternative choice for determining the FTL.[1] Since the field trial had already started, no change was made to the initial FTL for the Eastern Interconnection, but as additional interconnections joined the field trial the FTL for these new interconnections was based on 3 times ε_1 for the interconnection. This change broke the linkage between FTL and the UFRL and eliminated the justification for using 60 Hz as the only acceptable starting frequency.

As data accumulated from the Eastern Interconnection field trial, it became apparent that Time Error Correction (TEC) causes a detrimental reliability impact. The BAC SDT recognized this problem and initiated actions to provide a case to eliminate TEC based on its effect on reliability. This activity caused the RBC SDT and later the BARC SDT to defer any action on the substitution of Schedule Frequency for 60 Hz in the BAAL Equations until the TEC issue was resolved because the elimination of TEC would eliminate the need for change. When the ERO decided to continue to perform TEC, that decision relieved the BARC SDT of responsibility for the reliability impact of TEC and required the team to instead consider the impact that BAAL could have on the effectiveness of the TEC process and any conflicts that would occur with other standards.

Two conflicts have been identified between BAAL and other standards. The first is a conflict between the BAAL limit and Scheduled Frequency when an interconnection is attempting to perform TEC by adjusting the Scheduled Frequency to either 59.98 of 60.02 Hz. The second is a conflict that results in BAAL providing an ACE limit that is more restrictive that CPS1 when an interconnection is performing TEC. These problems can both be resolved by basing the BAAL Limit on Scheduled Frequency instead of 60 Hz. Eight graphs follow that show the conflict between BAAL as currently defined using 60 Hz and other standards and how the change from 60 Hz to Scheduled Frequency resolves the conflict.

The first four graphs show the conflict that is created while performing TEC. Under TEC the BAAL limit crosses both the CPS1 = 100% line and the Scheduled Frequency Line indicating the conflict between BAAL, CPS1 and TEC when BAAL is based on 60 Hz.

The next four graphs show how this conflict is resolved by using Scheduled Frequency as the base for BAAL. When BAAL is determined in this manner both conflicts are resolved and do not appear with the implementation of TEC.

Finally, resolving this conflict reduces the detrimental impact that BAAL has on some smaller BAs on the Western Interconnection during TEC.

[1] The initial value for FTL for the Eastern Interconnection was set at 50 mHz. Three time epsilon 1 for the Eastern Interconnection is 54 mHz.

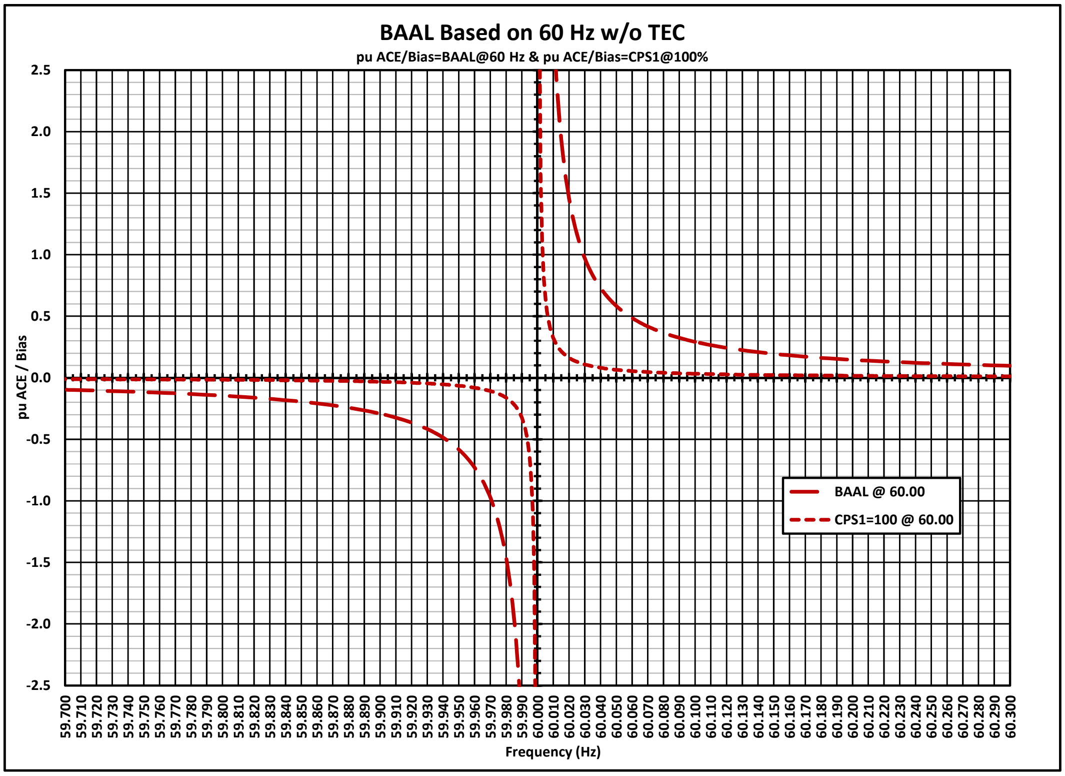

Figure 2. BAAL Based on 60 Hz w/o TEC

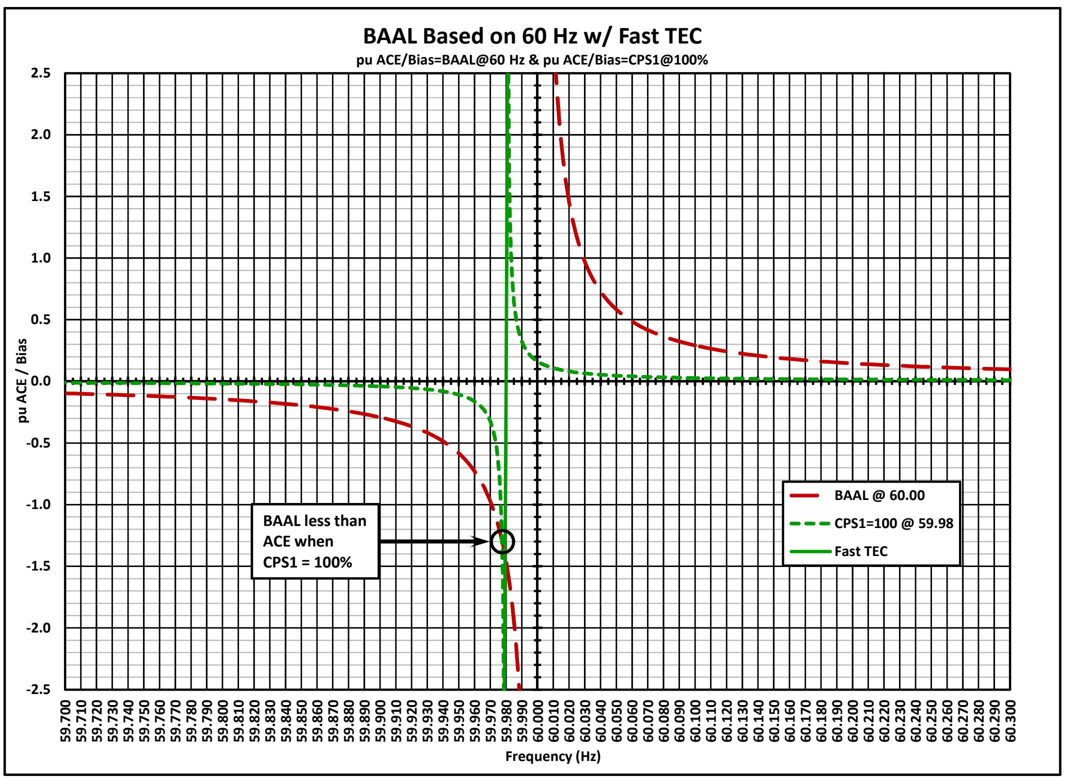

Figure 1. BAAL Based on 60 Hz w/ Fast TEC

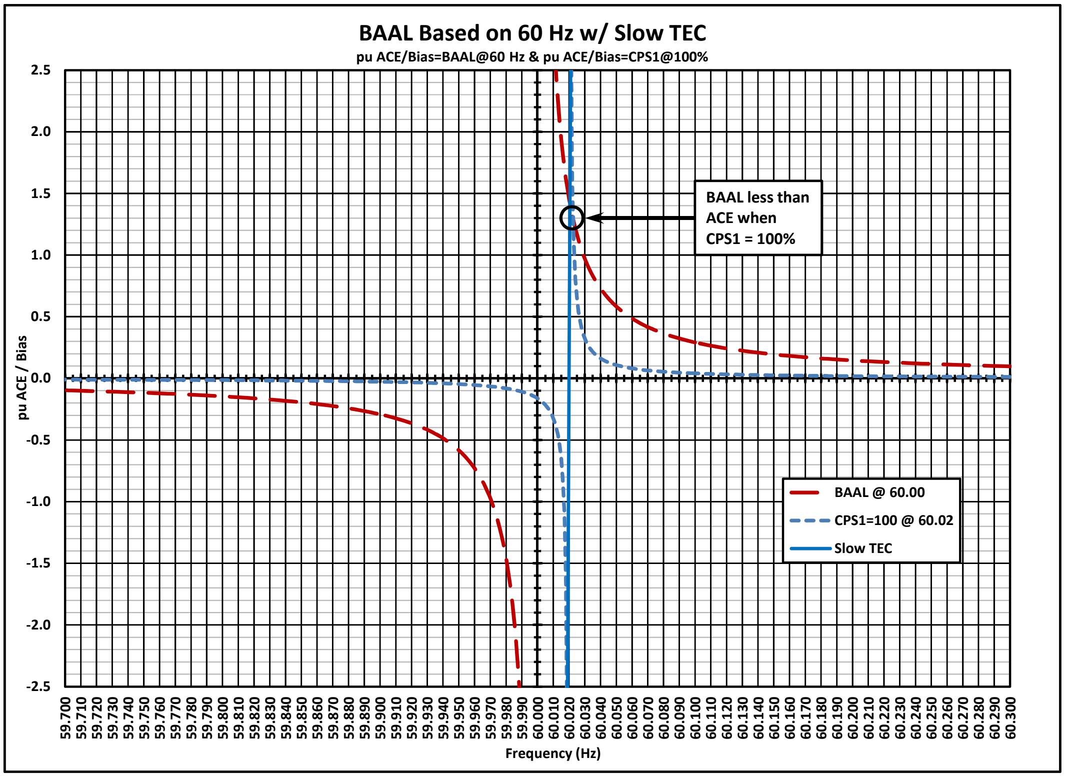

Figure 4. BAAL Based on 60 Hz w/ Slow TEC

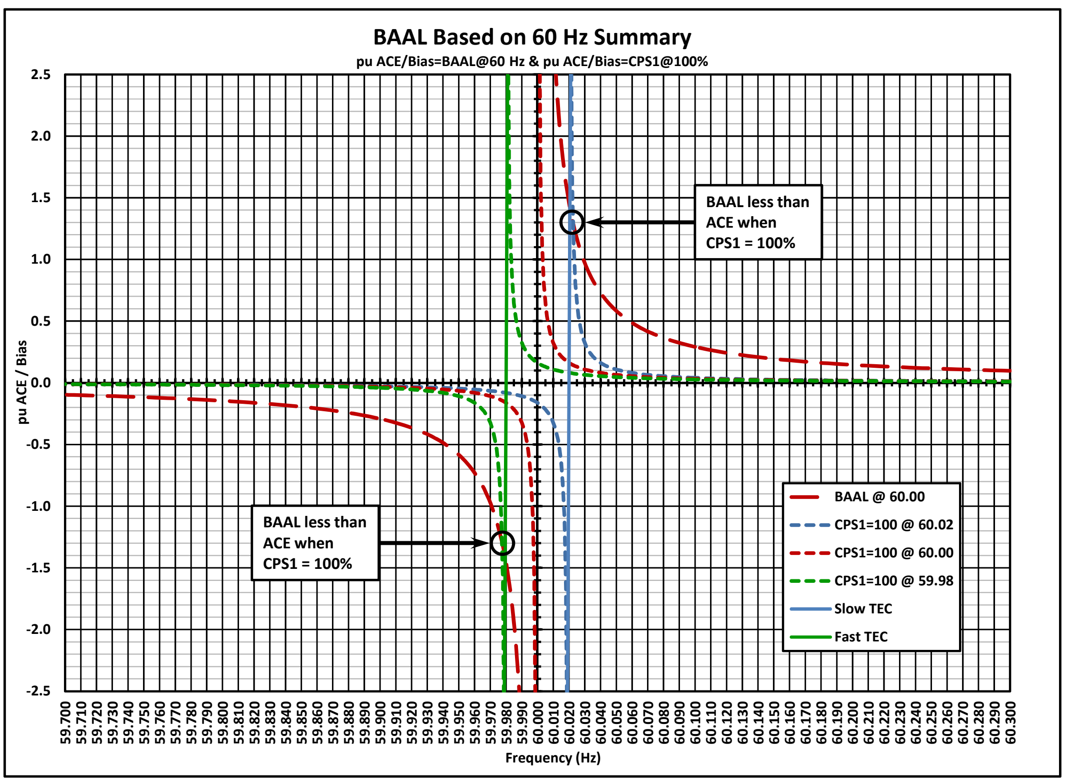

Figure 3. BAAL Based on 60 Hz Summary

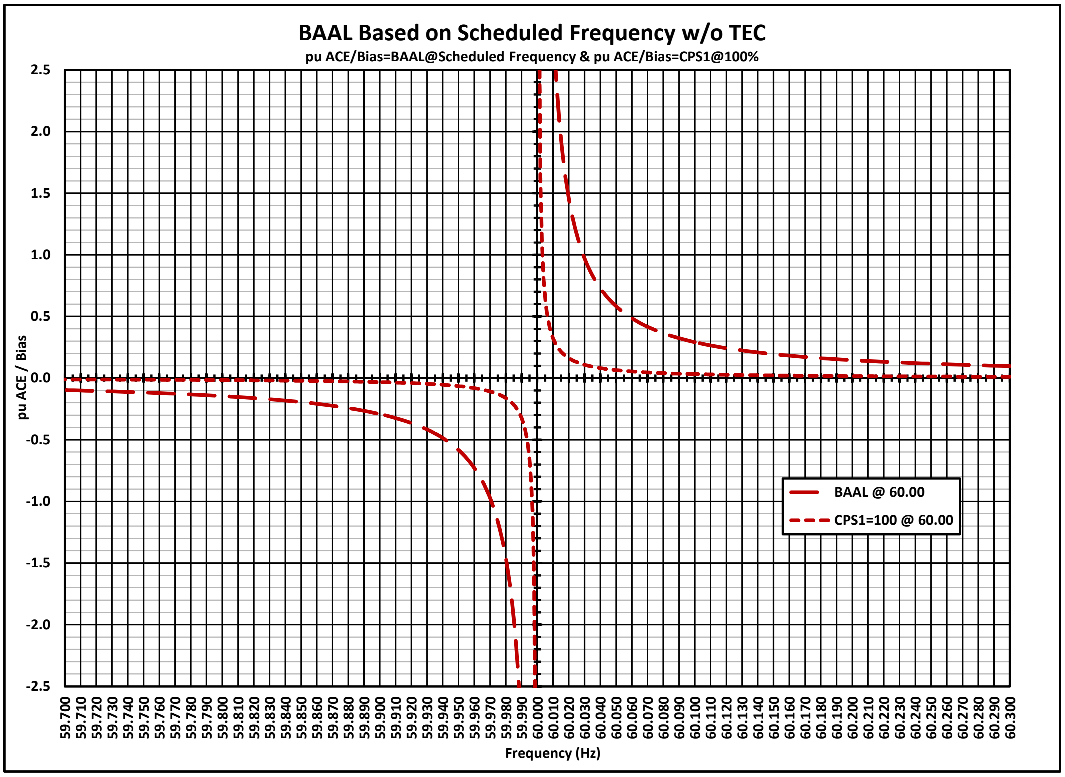

Figure 6. BAAL Based on Scheduled Frequency w/o TEC

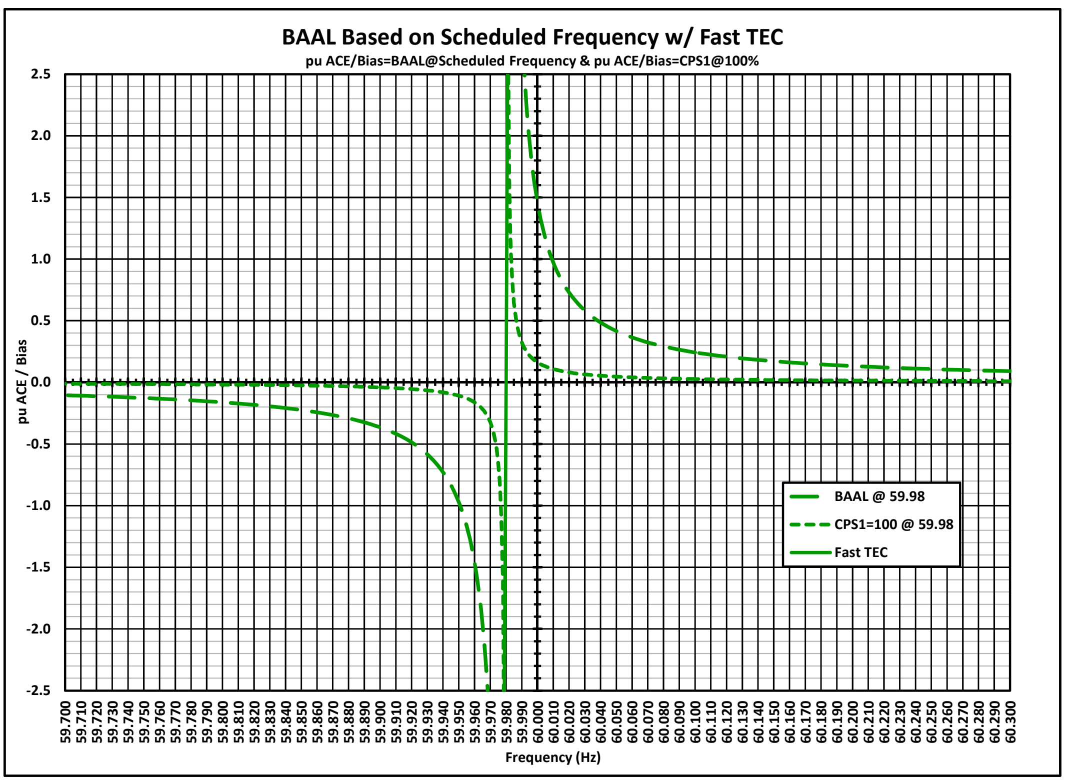

Figure 5. BAAL Based o Scheduled Frequency w/ Fast TEC

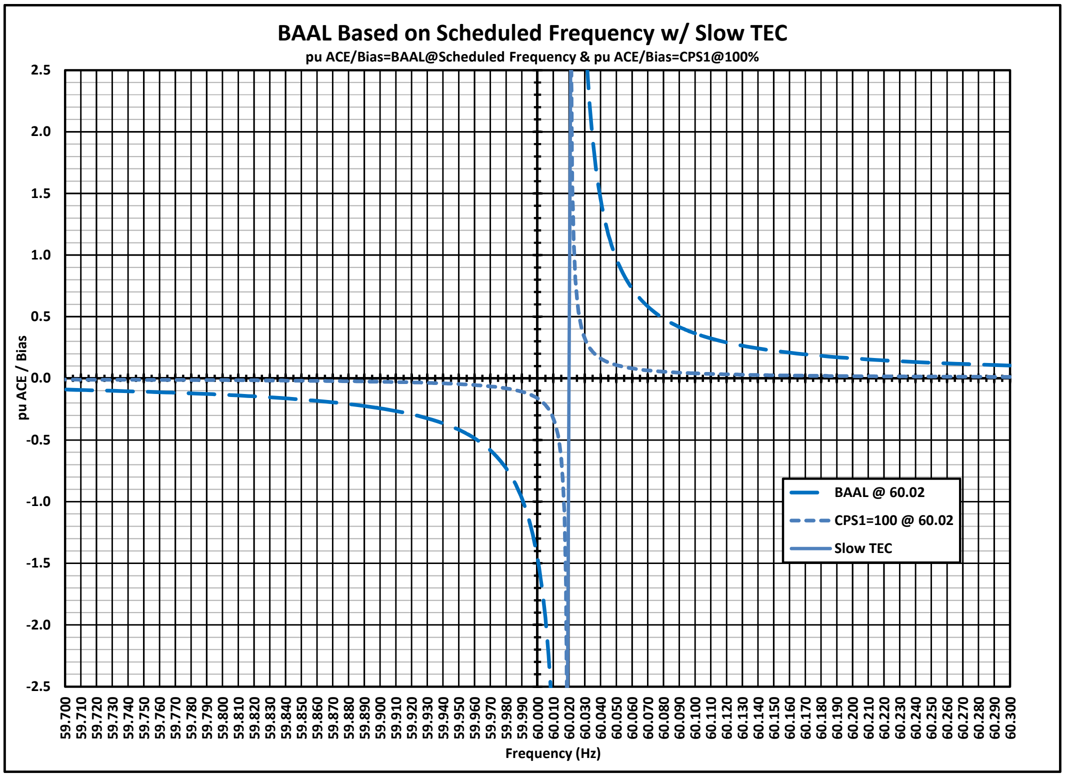

Figure 7. BAAL Based on Scheduled Frequency w/ Slow TEC

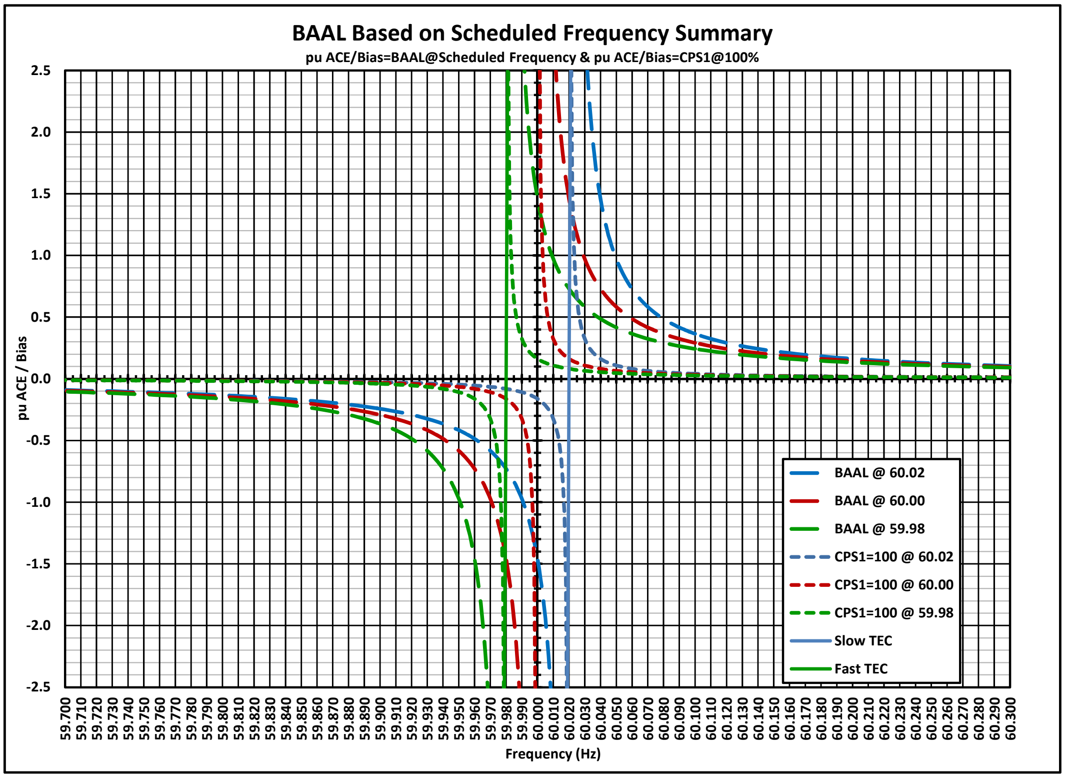

Figure 8. BAAL Based on Scheduled Frequency Summary

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BAL-001-~~1~~ 2 – Real Power Balancing Control Performance Standard Background Document

February 2013

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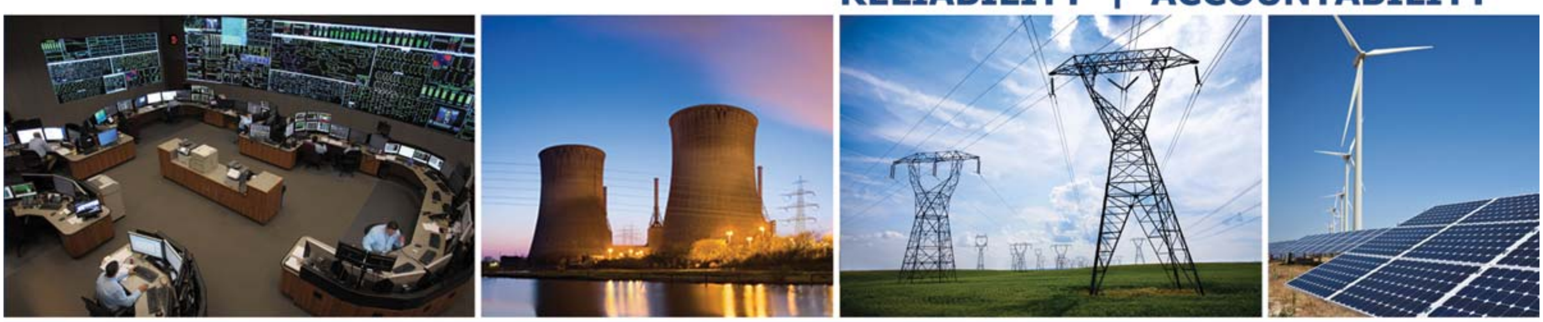

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R1. The Responsible Entity~~Each Balancing Authority~~ shall operate such that the ~~Balancing Authority's~~ Control Performance Standard 1 (CPS1), ~~(as~~ calculated in accordance with Attachment 1,~~)~~ is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each 12-month period, evaluated monthly~~, to support Interconnection frequency~~.

Background and Rationale

Requirement R1 is not a new requirement. It is a restatement of the current BAL-001-0.1a Requirement R1 with its equation and explanation of its individual components moved to an attachment, Attachment 1 - Equations Supporting Requirement R1 and Measure M1. This requirement is commonly referred to as Control Performance Standard 1 (CPS1). R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to support its Interconnection's frequency over a rolling one-year period.

CPS1 is a measure of a Balancing Authority's control performance as it relates to its generation, Load management, and Interconnection frequency when measured in one-minute averages over a rolling one-year period. If all Balancing Authorities on an Interconnection are compliant with the CPS1 measure, then the Interconnection will have a root mean square (RMS) frequency error less than the Interconnection's Epsilon 1.

A Balancing Authority reports its CPS1 value to its regional entity each month. This monthly value provides trending data to the Balancing Authority, NERC resources subcommittee, and others as needed to detect changes that may indicate poor control on behalf of the Balancing Authority. Requirement R1 remains unchanged, although the wording of the requirement was modified to provide clarity.

Requirement 2

R2. Each Balancing Authority shall operate such that its clock-minute average of R~~r~~eporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes,~~, its clock-minute Balancing Authority ACE Limit (BAAL)~~ ~~(~~as calculated in Attachment 2,~~)~~ for the applicable Interconnection in which the Balancing Authority~~it~~ operates~~ to support Interconnection frequency~~.

Background and Rationale

Requirement R2 is a new requirement intended to replace existing BAL-001-0.1a Requirement R2, commonly referred to as Control Performance Standard 2 (CPS2). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

The Balancing Authority ACE Limits (BAAL) are unique for each Balancing Authority and provide dynamic limits for its Area Control Error (ACE) value limit as a function of its Interconnection frequency. BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz. The FTL is equal to Scheduled Frequency~~60 Hz~~, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square (RMS) targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its FTL. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its FTL limits.

BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than Scheduled Frequency~~60 Hz~~, and BAAL high is for Interconnection frequency values greater than Scheduled Frequency~~60 Hz~~. BAAL values for each Balancing Authority are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from Scheduled Frequency~~60 Hz~~, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive 10-minute period was within the L_{10} bound 90 percent of all 10-minute periods over a one-month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency. For example, the Balancing Authority may be increasing or decreasing generation to meet its CPS2 bounds, even if this is a direction that reduces reliability by moving Interconnection frequency farther from its scheduled value. CPS2 allows a Balancing Authority to be outside its ACE bounds 10 percent of the time. There are 72 hours per month that a Balancing Authority's ACE can be outside its L_{10} limits and be compliant with CPS2.

In summary, the proposed BAAL requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an individual Balancing Authority's ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This requirement replaces and improves upon CPS2, which is not dynamic, is not based on Interconnection frequency, and allows for~~significant hours when~~ a Balancing Authority's ACE value to be unbounded for a specific amount of time during a calendar month~~s are unbounded~~.

Change From 60Hz to Scheduled Frequency

The base frequency for the determination of BAAL was changed from 60 Hz to Scheduled Frequency, $\mathbf{F_S}$. This change was made to resolve a long-standing problem with the requirement as first presented by the Balancing Resources and Demand Standard Drafting Team. The following presents information about the reason for the initial choice of 60 Hz and the need to change this value to Scheduled Frequency.

The initial BAAL equations were developed upon the assumption that the Frequency Trigger Limit (FTL) should be based upon Scheduled Frequency as shown in this draft of the standard. During initial development of values for the FTL the BRD SDT used a deterministic method for the selection of FTL based upon the Under-Frequency Relay Limit (UFRL) of an interconnection. Since the Under-Frequency Relay Limit of the interconnection is fixed the SDT chose to use a fixed value of starting frequency that would maintain a fixed frequency difference between the FTL and the UFRL. Therefore, the BRD SDT chose to base BAAL on a starting frequency of 60 Hz under the assumption that if the UFRL did not change then the FTL and base frequency should not change. The BAAL Field Trial was started using these values.

Shortly after the field trial started, directed research supporting the selection of the FTL for the Eastern Interconnection was completed. Unfortunately, the methods used to support the selection of an FTL for the Eastern Interconnection could not be repeated successfully for the other interconnections. Included in the final report was a recommendation that a multiple of 3 to 4 times the ε_1 for the interconnection could provide an acceptable alternative choice for determining the FTL.[1] Since the field trial had already started, no change was made to the initial FTL for the Eastern Interconnection, but as additional interconnections joined the field trial the FTL for these new interconnections was based on 3 times ε_1 for the interconnection. This change broke the linkage between FTL and the UFRL and eliminated the justification for using 60 Hz as the only acceptable starting frequency.

As data accumulated from the Eastern Interconnection field trial, it became apparent that Time Error Correction (TEC) causes a detrimental reliability impact. The BAC SDT recognized this problem and initiated actions to provide a case to eliminate TEC based on its effect on reliability. This activity caused the RBC SDT and later the BARC SDT to defer any action on the substitution of Schedule Frequency for 60 Hz in the BAAL Equations until the TEC issue was resolved because the elimination of TEC would eliminate the need for change. When the ERO decided to continue to perform TEC, that decision relieved the BARC SDT of responsibility for the reliability impact of TEC and required the team to instead consider the impact that BAAL could have on the effectiveness of the TEC process and any conflicts that would occur with other standards.

Two conflicts have been identified between BAAL and other standards. The first is a conflict between the BAAL limit and Scheduled Frequency when an interconnection is attempting to perform TEC by adjusting the Scheduled Frequency to either 59.98 of 60.02 Hz. The second is a conflict that results in BAAL providing an ACE limit that is more restrictive that CPS1 when an interconnection is performing TEC. These problems can both be resolved by basing the BAAL Limit on Scheduled Frequency instead of 60 Hz. Eight graphs follow that show the conflict between BAAL as currently defined using 60 Hz and other standards and how the change from 60 Hz to Scheduled Frequency resolves the conflict.

The first four graphs show the conflict that is created while performing TEC. Under TEC the BAAL limit crosses both the CPS1 = 100% line and the Scheduled Frequency Line indicating the conflict between BAAL, CPS1 and TEC when BAAL is based on 60 Hz.

The next four graphs show how this conflict is resolved by using Scheduled Frequency as the base for BAAL. When BAAL is determined in this manner both conflicts are resolved and do not appear with the implementation of TEC.

[1] The initial value for FTL for the Eastern Interconnection was set at 50 mHz. Three time epsilon 1 for the Eastern Interconnection is 54 mHz.

Finally, resolving this conflict reduces the detrimental impact that BAAL has on some smaller BAs on the Western Interconnection during TEC.

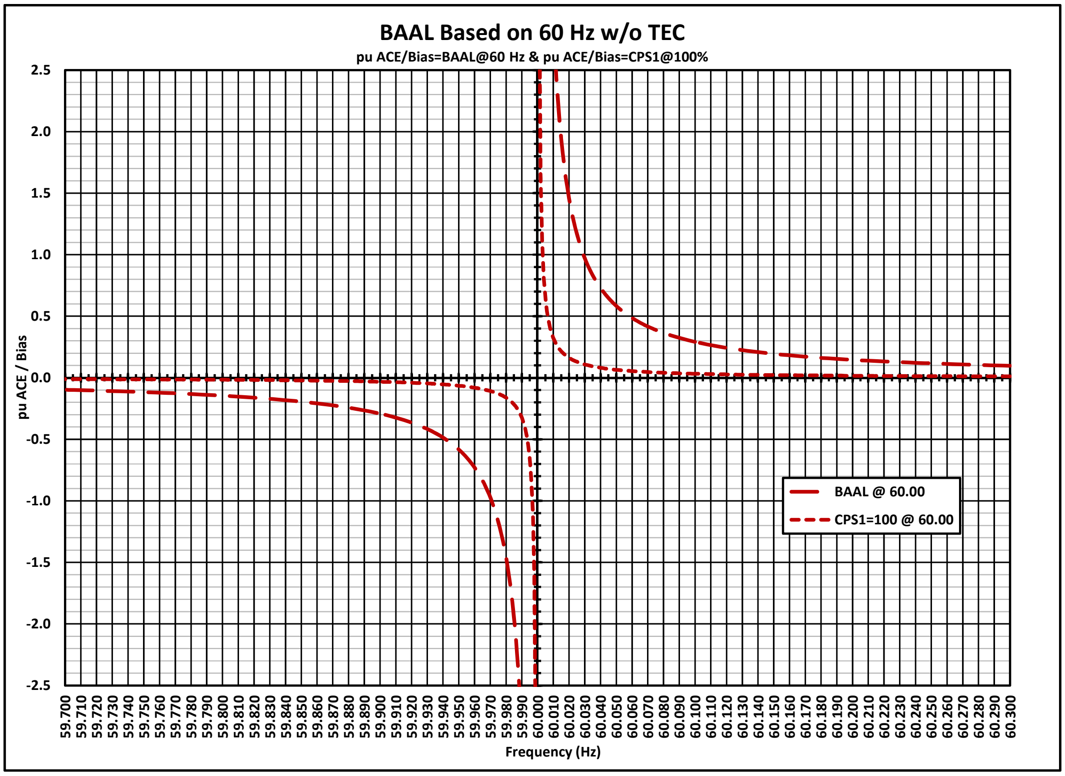

Figure 2. BAAL Based on 60 Hz w/o TEC

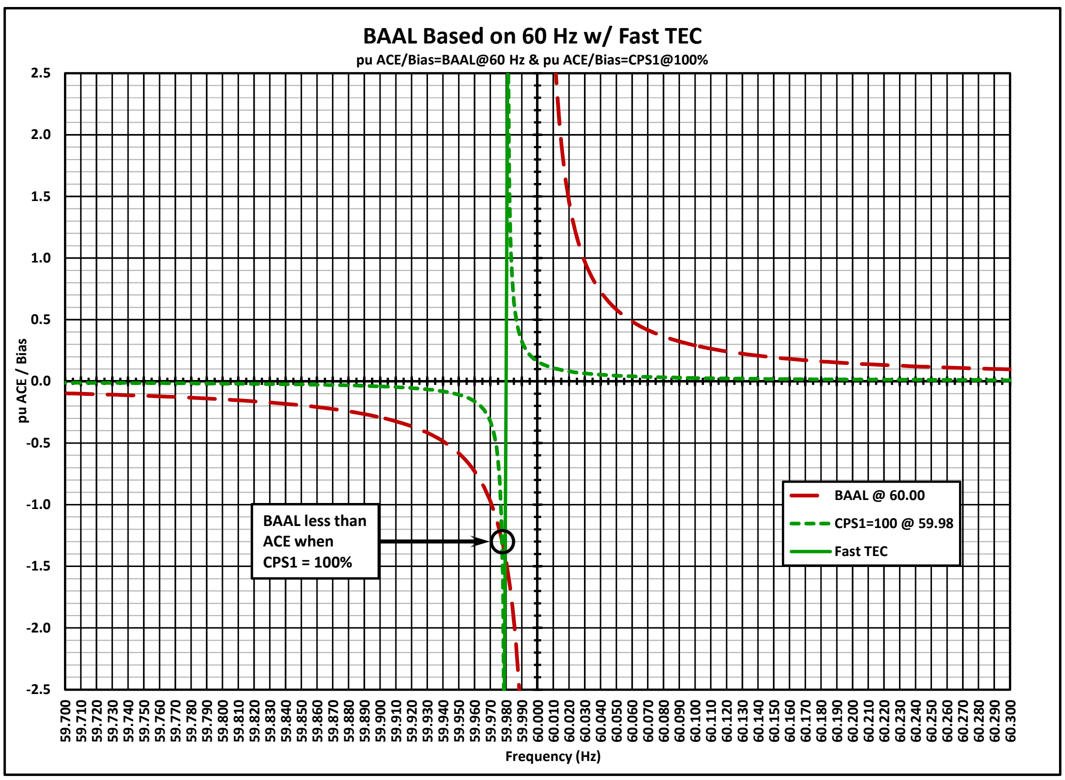

Figure 1. BAAL Based on 60 Hz w/ Fast TEC

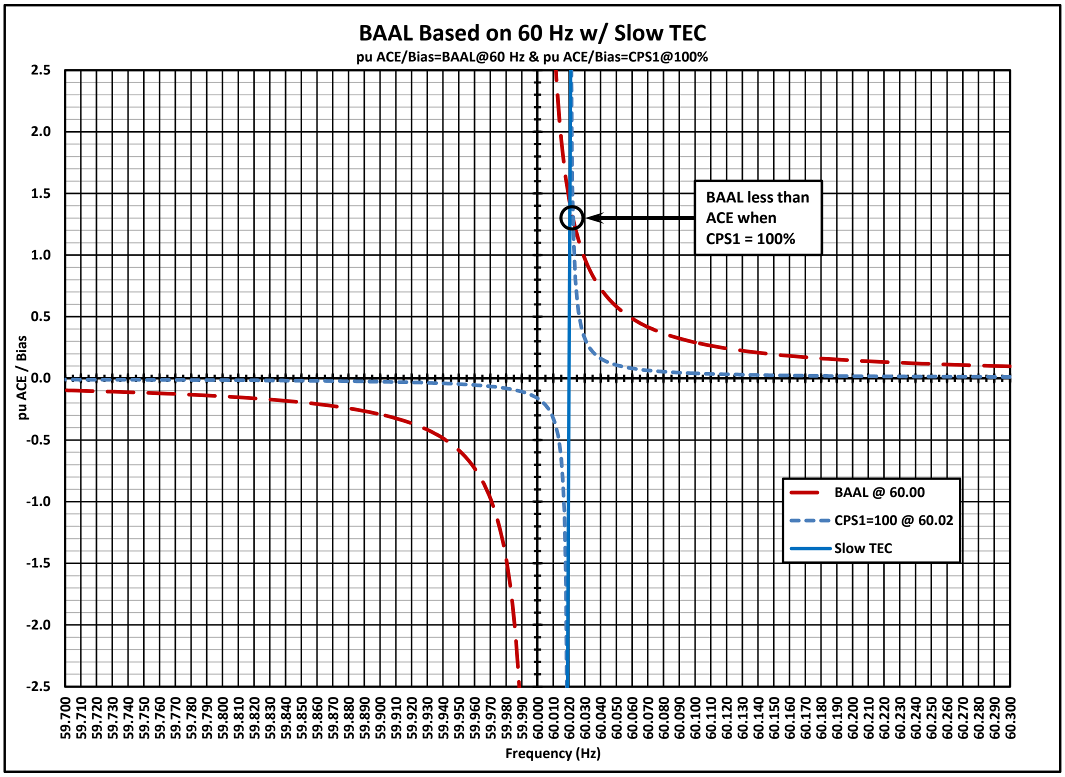

Figure 4. BAAL Based on 60 Hz w/ Slow TEC

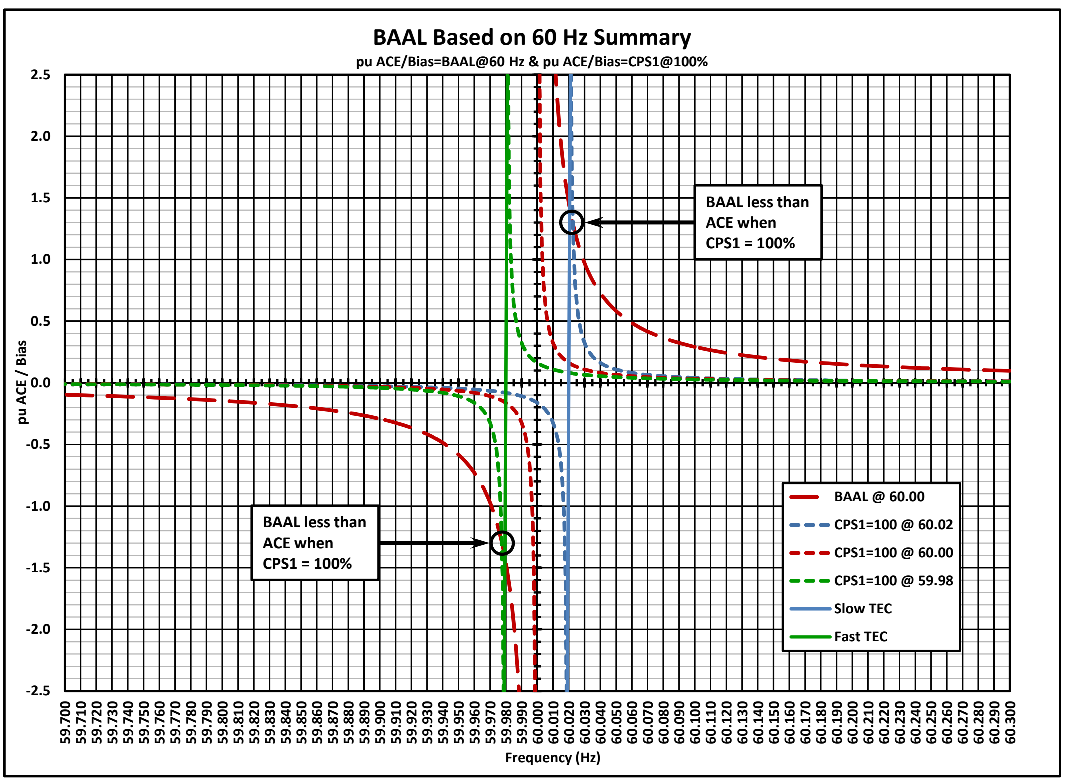

Figure 3. BAAL Based on 60 Hz Summary

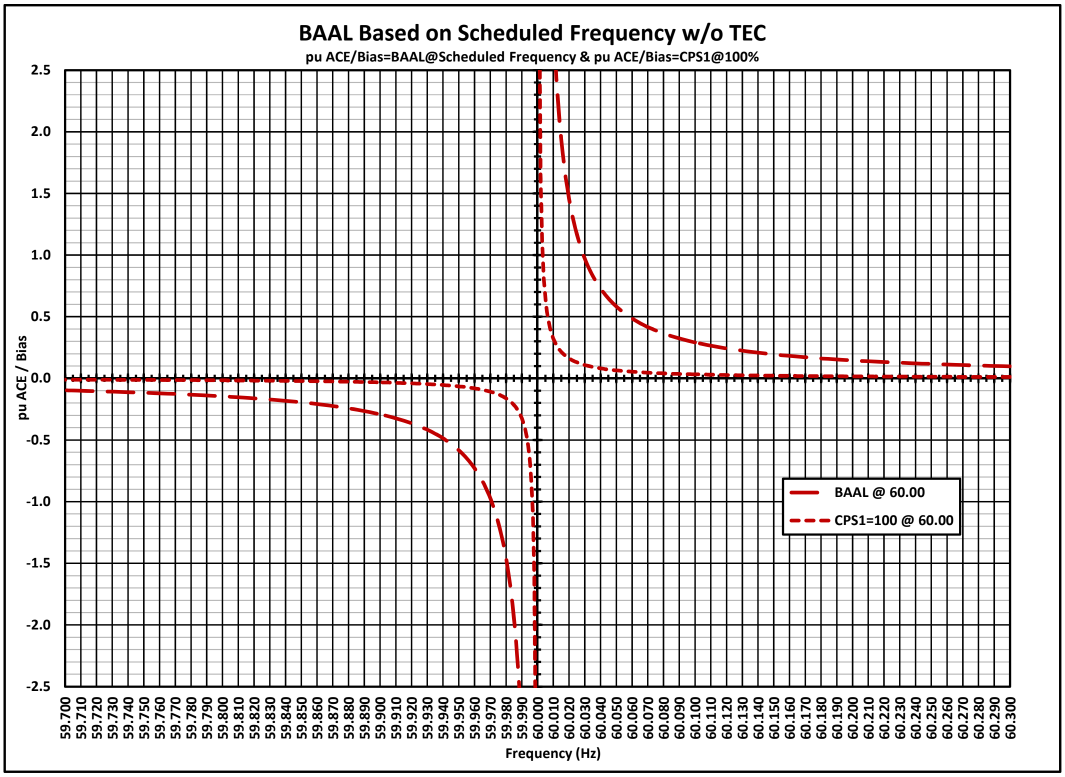

Figure 6. BAAL Based on Scheduled Frequency w/o TEC

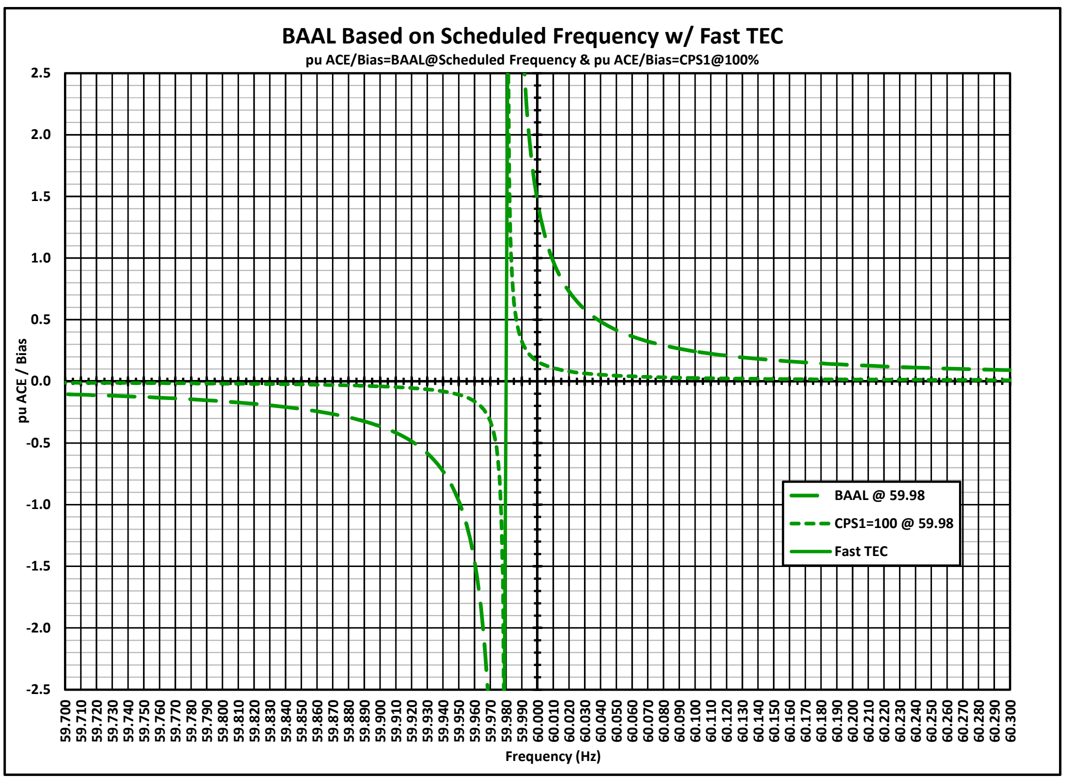

Figure 5. BAAL Based o Scheduled Frequency w/ Fast TEC

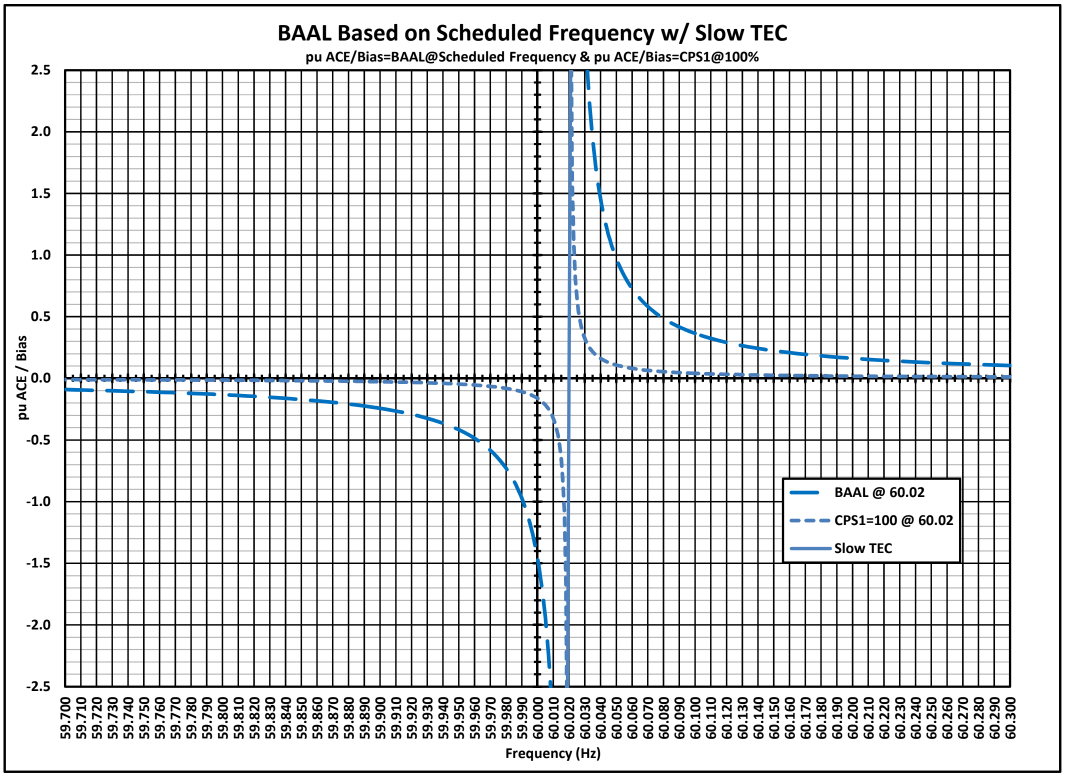

Figure 7. BAAL Based on Scheduled Frequency w/ Slow TEC

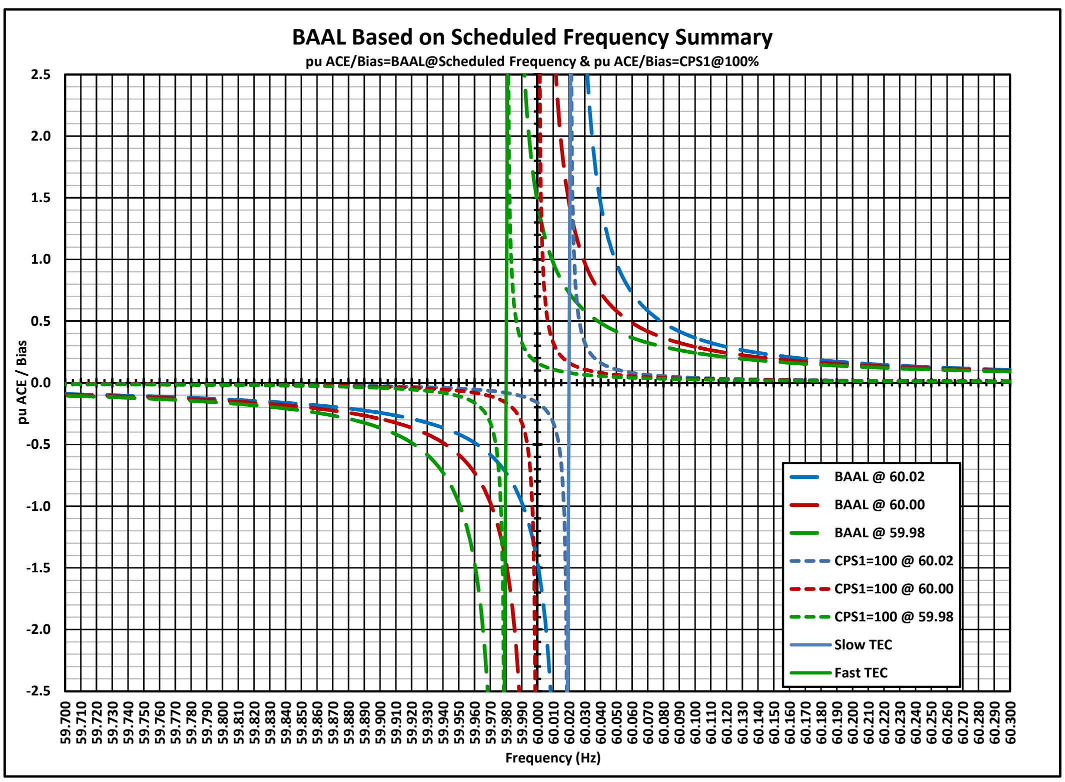

Figure 8. BAAL Based on Scheduled Frequency Summary

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Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-001-2 Real Power Balancing Control Performance Mapping Document

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each	This Requirement has been moved into BAL-001-2 Requirement R1	Requirement R1 The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each 12 month period, evaluated monthly. The calculation equation for CPS1 has been moved to Attachment 1 of BAL-001-2.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. $AVG_{Period}\ \underline{ACE1}$ $-10B$ The equation for ACE is: ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} where: • NI_A is the algebraic sum of actual flows on all tie lines. • NI_S is the algebraic sum of scheduled flows on all tie lines. • B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz. • F_A is the actual frequency. • F_S is the scheduled frequency. F_S is normally 60		

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Hz but may be offset to effect manual time error corrections. • I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.		
R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. AVG10-minute (ACE_i) ≤ L_{10} where:	This Requirement has been removed from BAL-001-2 and replaced with the proposed Requirement R2 for BAAL.	Requirement R2 Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
$L_{10}=1.65\ \epsilon_{10}\sqrt{(-10B_i)(-10B_S)}$ ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.		The calculation equation for BAAL is located in Attachment 2 of BAL-001-2.
R3. Each Balancing Authority providing Overlap Regulation Service shall	This Requirement has been moved into the BAL-001-2	Attachment 1 A Balancing Authority providing Overlap Regulation Service

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
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.	Attachment 1.	to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving Regulation Service.
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).	This Requirement has been moved into the BAL-001-2 Applicability Section.	Applicability Section 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-001-2, Real Power Balancing Control Performance. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature, and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-001-2:
There are two requirements in BAL-001-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-001-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a Standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-001-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-001-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation-per-day basis is the “default” for penalty calculations.

VSLs for BAL-001-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated CPS1.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of intervals the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-001-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated BAAL.	This is a new requirement. As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-2, BAL-002-2 and BAL-013-1)

Just a reminder…

Initial Ballot and Non-Binding Poll is now open through 8 p.m. Eastern April 25, 2013

Now Available

Initial ballots of the following three standards and non-binding polls of the associated Violation Risk Factors (VRSs) and Violation Severity Levels (VSLs) for Phase 1 of Balancing Authority Reliability-based Controls: Reserves is open through **8 p.m. Eastern on Thursday, April 25, 2013**:

- **BAL-001-2**- Real Power Balancing Control Performance
- **BAL-002-2**- Contingency Reserve for Recovery from a Balancing Contingency Event
- **BAL-013-1**- Large Loss of Load Performance

Background information for this project can be found on the project page.

Instructions

Members of the ballot pools associated with this project may log in and submit their vote for the standards and opinion in the non-binding polls of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Standards Announcement

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- **BAL-001-2**- Real Power Balancing Control Performance
- **BAL-002-2**- Contingency Reserve for Recovery from a Balancing Contingency Event
- **BAL-013-1**- Large Loss of Load Performance

Background information for this project can be found on the project page.

Instructions
Members of the ballot pools associated with this project may log in and submit their vote for the standards and opinion in the non-binding polls of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process
The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-001-2, BAL-002-2 and BAL-013-1

Initial Ballot and Non-Binding Poll Results

Now Available

Initial ballots for the following three standards and non-binding polls of the associated VRFs and VSLs in Phase 1 of Balancing Authority Reliability-based Controls: Reserves concluded at **8 p.m. Eastern on Thursday, April 25, 2013**:

- **BAL-001-2**- Real Power Balancing Control Performance
- **BAL-002-2**- Contingency Reserve for Recovery from a Balancing Contingency Event
- **BAL-013-1**- Large Loss of Load Performance

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the initial ballots.

Standards	Approval	Non-binding Poll Results
BAL-001-2	Quorum: 88.60 % Approval: 66.98 %	Quorum: 86.02 % Supportive Opinions: 73.19 %
BAL-002-2	Quorum: 88.51 % Approval: 42.75 %	Quorum: 86.46 % Supportive Opinions: 43.96 %
BAL-013-1	Quorum: 88.51 % Approval: 23.84 %	Quorum: 86.42 % Supportive Opinions: 25.24 %

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a recirculation ballot.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Reliability Standards Analyst, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-001-2 Initial Ballot
Ballot Period:	4/16/2013 - 4/25/2013
Ballot Type:	Initial
Total # Votes:	311
Total Ballot Pool:	351
Quorum:	**88.60 % The Quorum has been reached**
Weighted Segment Vote:	66.98 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**# Votes**	**No Vote**
1 - Segment 1.	90	1	45	0.662	23	0.338	8	14
2 - Segment 2.	10	0.9	6	0.6	3	0.3	1	0
3 - Segment 3.	79	1	41	0.651	22	0.349	7	9
4 - Segment 4.	24	1	13	0.722	5	0.278	0	6
5 - Segment 5.	75	1	37	0.661	19	0.339	11	8
6 - Segment 6.	54	1	31	0.66	16	0.34	5	2
7 - Segment 7.	2	0.2	2	0.2	0	0	0	0
8 - Segment 8.	6	0.4	4	0.4	0	0	1	1
9 - Segment 9.	3	0.3	1	0.1	2	0.2	0	0
10 - Segment 10.	8	0.6	3	0.3	3	0.3	2	0
Totals	**351**	**7.4**	**183**	**4.956**	**93**	**2.444**	**35**	**40**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Negative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	

1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Bruce Metruck	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Abstain	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN		
3	Avista Corp.	Scott J Kinney	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	National Grid USA	Brian E Shanahan	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Self	Herb Schrayshuen	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	

5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Abstain	
5	Colorado Springs Utilities	Michael Shultz	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Abstain	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	

5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto	Abstain	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Negative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis	Negative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew	Affirmative	

8		Roger C Zaklukiewicz	Affirmative	
8		Robert Blohm	Affirmative	
8		Edward C Stein	Affirmative	
8	Self	Debra R Warner	Abstain	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy
404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-binding Poll Results

Project 2010-14.1 BAL-001-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-14.1 BARC Non-binding Poll BAL-001-2
Poll Period:	4/16/2013 - 4/25/2013
Total # Opinions:	283
Total Ballot Pool:	329
Summary Results:	86.02% of those who registered to participate provided an opinion or an abstention; 73.19% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	

1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	

1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		

3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Self	Herb Schrayshuen	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Abstain	
5	Colorado Springs Utilities	Michael Shultz	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	

5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Abstain	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	

5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis	Negative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	

6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Robert Blohm	Affirmative	
8		Edward C Stein	Affirmative	
8	Self	Debra R Warner	Abstain	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (55 Responses)
Name (31 Responses)
Organization (31 Responses)
Group Name (24 Responses)
Lead Contact (24 Responses)
Contact Organization (24 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (10 Responses)
Comments (55 Responses)
Question 1 (38 Responses)
Question 1 Comments (45 Responses)
Question 2 (25 Responses)
Question 2 Comments (45 Responses)
Question 3 (25 Responses)
Question 3 Comments (45 Responses)

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Group
Salt River Project
Bob Steiger
Electric Reliability Compliance
Yes
Yes
There is reasonable concern that the large ACE values that the standard permits under certain conditions will cause excessive unscheduled flow on qualified transmission paths. We believe that this issue can be managed by the Reliability Coordinator through enforcement of existing standards, but may require changes to current practices.
No
Individual
Tom Siegrist
EnerVision, Inc.
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental

regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term “RRSG” is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined “entities”. Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared through the FMWG.
No
We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.
Yes
The wording of 4.1.2 should be rearranged to more explicitly define what the “Responsible Entity” is. Responsible entity should not be capitalized unless it is going to be defined in the NERC Glossary.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
Individual
John Tolo
Tucson Electric Power Co
Yes
Yes
Yes
Using the newly-defined term Reporting (ATEC) ACE is a positive change. Using Scheduled Frequency instead of 60Hz in the BAAL calculation is also a positive change.
Individual
Rich Hydzik
Avista
Yes
No
The RBC Field Trial in the WECC provided enough information to determine if RBC had any effects on reliability. The WECC PWG’s July 2012 report to the WECC OC clearly documented frequency error was increasing over previous operation under CPS2. It documented increasing frequency in the negative direction in heavy load hours (particularly morning and evening peaks) and increasing frequency error in the positive direction during light load hours. This report also shows Epsilon 1 and Epsilon 10 increasing significantly over past CPS2 performance years. Manual time error corrections and hours of manual time error corrections are approximately double what they had been. The PWG report documents increasing unscheduled flow events with the ACE Transmission Limit (ATL) being increased or eliminated. This has continued on into 2013. This indicates that RBC has a negative effect on path flow control and management. Increasing inadvertent accumulations are also documented in the PWG report. Increasing inadvertent, unscheduled flow events and curtailments, and prolonged frequency deviations beyond 0.030 Hz are not hallmarks of a reliable system. No studies, or actual events, have demonstrated that the WECC system can perform for a 2800 MW (G-2)

generation loss with an initial frequency of 59.94 Hz or lower. Additional control problems are created when frequency deviations beyond 0.030 Hz occur, exceeding governor deadband on generating units (IEEE standard deadband). If these units are being used for Automatic Generation Control (AGC), they will move to governor control, generally disabling the AGC functionality. This does not add to system reliability, and likely detracts from it. The RBC formula advantages larger Balancing Authorities by allowing looser control and wider frequency ranges. Whereas a smaller BA may see the BAAL limits quickly shrink at deviations near 0.050 Hz, a larger BA can still run a large ACE, creating inadvertent flow and secondary control problems for smaller BA's. Finally, loose ACE control effectively eliminates the effectiveness of the WECC Automatic Time Error Correction system. WECC ATEC depends on CPS2 compliance in order to ensure that a BA is continuously paying back its accumulated Primary Inadvertent balance. With the loose limits of RBC, the Primary Inadvertent payback term is small enough that it may not even influence the BA's AGC control algorithm. This can be clearly seen by the invreasing WECC frequency deviation beginning with the field trial in 2010. ATEC was implemented in WECC in 2003, and low frequency deviation from 2003-2009 is easily seen the PWG 2012 WECC OC report. R2 is not a frequency control requirement under all conditions, it is a requirement that is used under normal conditions. It is designed to operate around small frequency deviations. For large frequency deviations, frequency support is required and measured by ACE recovery under BAL-002 (DCS). With respect to R2/M2, how many times can a BA exceed BAAL limits for 30 minutes? Can a BA exceed BAAL for 27 minutes every hour? A limit based on so many minutes exceeding BAAL per month or some similar measure may be more likely to incent the desired control performance. How do you measure severity if an event happens many times, but never exceeds 30 minutes? Is 29 minutes ok and 31 minutes a risk to the interconnection? Comments: "BAL-001-1 Real Power Balancing Control Standard Background Document" Page 4 has an illuminating statement. "CPS2 is: Designed to limit a Control Area's (now BA) unscheduled power flow." This is a significant issue in the WECC. Unscheduled power flow becomes unmanageable without the CPS2 requirement. There is no other way to control BA to BA power flow if a BA is not required to maintain its Net Actual Interchange within a limit. The summary statement on page 6 is not supported by the field trials. The summary statement says that RBC improves upon CPS2 by dynamically altering ACE limits based on frequency. The WECC field trial conclusively demonstrates that frequency control is worse and frequency error is greater, indicating RBC decreases reliability compared to CPS2. The inability to control path flows effectively, requiring unscheduled flow mitigation to remain within System Operating Limits, inherently decreases reliable operation. CPS2 takes frequency into account with the frequency component of the ACE equation. To claim that operating to the ACE equation does not inherently support system frequency is not logical. The CPS2 requirement should be retained, and the BAAL should not be adopted.
No
Looser AGC control resulting from implementation of BAAL results in unscheduled flow. Increasing unscheduled flow events significantly impact each participant in the energy markets. Schedules are curtailed to accommodate RBC, thus favoring one form of generation over another. In this case, variable resources are given an advantage looser control and other parties are impacted. Although this appears to be an economic issue, any time energy schedules are curtailed for reliability reasons, reliability is negatively affected.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Although Manitoba Hydro agrees with the definitions, we have the following suggestions: (1) NIA (Actual Net Interchange) - capitalize the word 'tie lines' because it appears in the Glossary of Terms. (2) NIS (Scheduled Net Interchange) - capitalize the word 'tie lines' because it appears in the Glossary of Terms. Also, the words 'Net Interchange Actual' should be rewritten as 'Net Actual Interchange' and the word 'Interchange' de-capitalized in 'scheduled Interchange'. (3) Regulation Reserve Sharing Group - capitalize the word 'regulating-reserve' because it appears in the Glossary of Terms. Also, the '-' should be removed from 'regulating-reserve'. (4) Reporting ACE - capitalize the word 'net actual interchange'. Also, add 'net' to 'scheduled interchange' and capitalize, because definitions appear in the Glossary of Terms. (5) 10 - capitalize 'frequency bias setting'. (6) IME (Interchange Meter Error) - the words 'net interchange actual (NIA)' should be re-written as 'Net Actual Interchange' and capitalized. Also, de-capitalize the last instance of 'Interchange'. (7) IATEC (Automatic Time Error Correction) - capitalize the word interconnection'. (8) H - de-capitalize 'Hours' or is this a Clock Hour? (9) PIIaccum - capitalize the words 'interconnection', 'net interchange schedules', 'net interchange', and 'scheduled frequency'.
Yes
Although Manitoba Hydro is in support of the standard, we have the following clarifying suggestions: (1) 1. (Proposed) Effective Date in both the Standard and Implementation Plan - remove the " ' " following the word 'Trustees' because it is not defined this way in the Glossary of Terms. (2) Applicability 4.1.2 - add an 's' on the end of the word 'period'. In addition, add the word 'the' before 'governing rules'. (3) Data Retention - capitalize three instances of 'compliance enforcement authority' in this section. (4) R1 - the words '12 month period' should be changed to 'rolling 12 month basis' for consistency with the VSL table. (5) R1 - for clarity, 'it' should be specified as the 'Responsible Entity'. (6) R2/M2 - please clarify if this requirement/measure should refer only to Balancing Authority as opposed to Responsible Entity? (7) R2 - add the words 'accordance with' before 'Attachment 2'. (8) M1, M2 - the term 'Energy Management System' is not found in the Glossary and should be defined. (9) VSL, R2 and Attachment 1, CPS1 - add a '-' between

the words ‘clock minutes’ for consistency with the standard. In addition, the words ‘for the applicable Interconnection’ should be added for consistency with the language of R2 and the VSL for R1. (10) General - there is inconsistency throughout the standard and Attachments with respect to the following words: ‘12 month period’, ‘rolling 12 month basis’, ‘12-calendar months’, ‘12-month’. We suggest selecting one of these terms and using it throughout the standard and attachments.
Yes
(1) Section D, Compliance, 1.1 – the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (2) Implementation Plan, Regulation Reserve Sharing Group - capitalize the words ‘regulating reserve’ because they appear in the Glossary of Terms. (3) Implementation Plan, Reporting ACE - capitalize ‘net actual interchange’ and change ‘scheduled Interchange’ to ‘Net Scheduled Interchange’. (4) Implementation Plan - make same changes to definitions in Implementation Plan as suggested in Question 1 of this commenting request. (5) VRF/VSL - capitalize ‘bulk electric system’ in both the High Risk Requirement and Medium Risk Requirement sections.
Group
seattle city light
paul haase
seattle city light
Yes
There are differing references to Regulating Reserve Sharing Group and Reserve Sharing Group between BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the Standards.
No
Seattle City Light supports the implementation of BAAL limits to replace CPS2, but think this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Specifically, Seattle experienced good results in the Reliability Based Controls field trials and supports the RACE and BAAL concepts. However, Seattle has concerns about the compliance risk introduced by the many new definitions and new types of reserve sharing groups proposed under this draft. In particular are the relations among Regulation Reserve Sharing Group, Reserve Sharing Group, and Balancing Authority ability to designate one or another of these groups as responsible entity. For example, as currently written there may be a possibility of conflict between the applicability of BAL-001-2 and Requirement R2 of the Standard. As written Applicability Section 4.0 states the Standard is applicable to: 4.1 Balancing Authority 4.1.2 A balancing Authority that is a member of Regulation Reserve Sharing Group is the Responsible Entity only in period during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Regulation Reserve Sharing Group. 4.2. Regulation Reserve Sharing Group. Further Requirement R2 of the Standard states that: R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] Seattle finds the Standard is not clear if requirement R.2 is applicable to the Regulation Reserve Sharing Group as a group or to all BAs individually participating in Regulation Reserve Sharing Group. As currently written a BA can argue that R.2 is not applicable if they are participating in Regulation Reserve Sharing Group, and Seattle is not sure if this was the intent of the Standard Drafting Team. Another example is that Attachment 1 used to describe how to calculate CPS1 does not appear to be complete. It needs to be revised to include the methodology for calculating the CPS1 for the Regulation Reserve Sharing Group. Seattle is also concerned that BAL-001-2 R2 “…more than 30 consecutive clock-minutes…” requirement represents too long a time, and should be changed to a shorter time frame to better reflect the existing and proposed sub-hour scheduling windows and other Standards limiting the time that a Balancing Authority is not positively supporting system frequency.
Yes
The Guidelines document purported to address issues such as those discussed in question 2 above will not be available for review until summer 2013. Lacking such a document, Seattle City Light cannot support this draft of BAL-001-2.
Group
MRO NERC Standards Review Forum
Russel Mountjoy-Secretary
MRO
No
We don’t understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control standard is referenced in the changes, RBC deals with a 30

minute limit on ACE and not redefinition of ACE and the creation of new entities.
Assuming we are wrong and that the drafting team has authority under their SAR to modify BAL-001, we have the following comments. 1) Unless there is justification we missed, the new definitions should be removed. 2) With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Tertiary Control. (Alternatively, clarify that IATEC is equal to ITC. This way the reporting and operating number would be the same.) The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their dead-bands under BAL-003-1.
Yes
1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. The NSRF believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. The NSRF is not asking for a change to the standard, just a clear statement for the purposes of documenting compliance.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst votes in the Negative due to the “Regulation Reserve Sharing Group” being an applicable Entity and the fact that there is no functional or Registered Entity defined as a “Regulation Reserve Sharing Group”. Absent any Entities registered as a “Regulation Reserve Sharing Group”, compliance cannot be assessed against this entity, thus making any requirements applicable to the “Regulation Reserve Sharing Group” unenforceable.
Individual
Joe Tarantino
SMUD
No
While the definitions are acceptable, terminology within the standards that call these discrete entities would be better identified as an overarching Reserve Sharing Group that would encompass the various terms: RRSG, RRSGRA ect. Recommend replacing all unique terminology to only include the Reserve Sharing Group in the BAL-001.
See comment in response #1.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
No
With the introduction of the Regulating Reserve Sharing Group there appears to be a registration gap. There currently isn’t a Regulating Reserve Sharing Group entity in the Functional Model. It would appear that such a registration would have to be made in order to be able to hold the Regulation Reserve Sharing Group accountable for compliance purposes. Providing this is done, then R1 and R2 should reflect the applicability to both the Balancing Authority and the Regulation Reserve Sharing Group. As written R1 requires any applicable BA to maintain CPS1 for the Interconnection within which it operates at 100 percent or higher. The rolling 12-month calculation needs additional clarification also. We suggest the requirement should be rewritten to read: The Responsible Entity shall operate such that its Control Performance Standard 1 (CPS1), calculated based on the applicable Interconnection in which it operates in accordance with Attachment 1, is greater than or equal to 100 percent for each consecutive 12-month period. Each consecutive 12-month period shall be evaluated monthly. As written, R2 applies only to a Balancing Authority. It should be reworded to apply to both a Balancing Authority or Regulation Reserve Sharing Group as is R1. Substitute Responsible Entity for Balancing Authority in the requirement. Likewise we would suggest deleting the comma following

‘Attachment 2’ in R2. This links the ending phrase of the sentence to the calculation, where it should be, more tightly. In the last line of Attachment 2, insert ‘Overlap’ in front of ‘Regulation Service’.
Yes
Add an ‘s’ to ‘period’ in the 2nd line of 4.1.2 in the Applicability Section. Replace ‘greater’ with ‘more’ in the Moderate, High and Severe VSLs for R2. On Page 7 of the Background Document, in the 4th line of the 3rd paragraph, replace ‘that’ with ‘than’ in front of CPS1.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
Midwest ISO
Individual
Greg Travis
Idaho Power Company
Yes
Yes
I believe that operating under the BAAL does not pose a threat to reliability and could help mitigate variable resource integration provided that BAs do not stress the limits during normal operations. If BAs could be encouraged to follow expected changes in system demand reasonably close during normal conditions then the system could more readily absorb unexpected events. However, I'm not sure how this can be addressed within a standard.
Group
PacifiCorp
Ryan Millard
PacifiCorp
Yes
PacifiCorp supports this draft.
No
Individual
Michael Falvo
Independent Electricity System Operator
No
We do not see the need to create these terms. We understand that the first term (RRSG) is used in the applicability section and arguable in R1. However, the proposed standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. Furthermore, since the term RRSG is in the applicability section of the standard, it implies that this is a new functional entity. In order for this term to have applicability, it needs to have defined roles. This definition should be vetted through the functional model working group and included in the functional model PRIOR to being included in BAL-001.
No
While we do not see the need to create the two new terms (RRSG and TTSG Reporting ACE), if the terms were to be included, the term RRSG should be vetted through the functional model working group PRIOR to including it in this standard as it appears to be a new functional entity. As such, it’s roles should be defined in the functional model prior to being incorporated into any NERC standards. We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. We generally supported the previous draft that stipulates the requirements for each BA. We are unable to support the currently posted version as it appears to place requirements on both individual BAs and the RRSG but the obligations

for the latter is not clearly stipulated in the standard. At any rate, we do we see a need to have that latter (RRSG) requirements stipulated for the RRSG so long as the standard places obligation to each BA to meet the CPS1 and BAAL requirements.”
Individual
Howard F. Illian
Energy Mark, Inc.
Yes
Yes
Yes
Individual
Don Schmit
Nebraska Public Power District
No
The applicability section of the standard allows for periods of time when a BA may be responsible for meeting the requirements of this standard and times when a Regulation Reserve Sharing Group may be responsible for meeting the requirements of this standard. However R1 requires calculating a 12 month average CPS 1. Neither the requirement nor the attachment address how a responsible entity is to handle those periods, which may be portions of a month, day or hour when they are not responsible for meeting the requirements. If the period is to be treated as bad data, the standard or attachment that details the calculation needs to specify how those periods are handled. The term “active status” used in section 4.1.2 is not a defined term and may not be included in any regulation reserve sharing agreements. There should be more clarity around this term. Given the concerns noted above, are there minimum time periods when a regulation reserve sharing group may not be in “active status”. For example, can a regulation reserve sharing pool be inactive for a portion of an hour, or conversely only be active for a portion of the hour? The standard needs more clarification on what active status means and how frequently the status can change.
Group
SERC OC Standards Review Group
Stuart Goza
Tennessee Valley Authority
Yes
We are concerned that the term “Reporting ACE” used in this definition has a different historic meaning than what is being formalized in this proposed standard. We recommend labeling this term as “Regulation Reporting ACE.”
: We do not believe it is appropriate to include a region or interconnection specific definition in a continent-wide standard. However, we would not object to including a generic term for time-control adjustment. These comments were also supported by Ron Carlsen with Southern Company. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Group
PJM Interconnection, L.L.C
Stephanie Monzon
PJM Interconnection, L.L.C

No
PJM disagrees with the Interconnection specific inclusion of IATEC in the Reporting ACE definition. The definition of ACE is internationally recognized. It is inappropriate for the SDT to change that definition because of one region in North America. PJM believes all Interconnections should adhere to a common ACE equation definition and that Interconnection specific differences should be addressed through development of a regional standard, as was BAL-004-WECC-01.
PJM is, in general, supportive of this standard with the exception noted in comments for question 1.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Agree
ERCOT
Individual
Angela P Gaines
Portland General Electric Company
Yes
PGE is generally supportive of the underlying goal of this standard revision – increased coordination between BAs for efficiently and reliably, meeting Control Performance Standards through the development of a Regulation Reserve Sharing Group, or other yet to be named program. However, PGE is concerned the proposed standard does not adequately address the reliability concerns associated with unscheduled flow and degraded frequency response metrics that have been witnessed with the current WECC Reliability Based Control pilot program. PGE believes the unique physical transmission properties of the Western Interconnect dictate a need for increased consideration of reliability protections for our region prior to the adoption of new nation-wide standards.
Individual
Kathleen Goodman
ISO New England Inc.
No
The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term “RRSG” is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined “entities”. Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared through the FMWG.
No
We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.
The wording of 4.1.2 should be rearranged to more explicitly define what the “Responsible Entity” is. Responsible entity

should not be capitalized unless it is going to be defined in the NERC Glossary. There is a concern that the operations under the BAL-001 standard will not meet the frequency performance expectation of BAL-003 (e.g., frequency above 59.974 Hz at least 95% of the time for the Eastern Interconnection). If the frequency performance falls below this target, then the Interconnection Frequency Response Obligation (IFRO) may no longer be adequate for reliability. Additionally, it could become burdensome to the industry if the IFRO becomes volatile in the upward direction, as additional frequency response is difficult to obtain and has a rather long lead time for increasing its supply.
Individual
Thad Ness
American Electric Power
No
It is not clear what exact intent the drafting team has in the introduction of the term “Regulation Reserve Sharing Group”. This term is specified in the Applicability section, so is it the drafting team’s intent to propose that this new term be established as a new Functional Entity? If that is not the intent, we believe it is mistaken to specify any applicability to any grouping that does not have formal, registered members.
AEP has suggested modifications regarding scope and content in our responses to Q1 & Q3. Most concerning to us are the topics raised in our response to Q3 (below).
Yes
We would encourage the drafting team to provide Generator Operators with the appropriate requirements to support the Balancing Authorities. As currently drafted, the Balancing Authority may be the sole entity responsible for meet the obligations of the standard, and yet it does not have direct control over the Generator Operator to ensure the BA receives what is needed. At the least, the BA might need some sort of recourse specified in the event a Generator Operator is not acting in a cooperative manner (for example, a Generator Operator who refuses to adhere to their agreed-upon schedule in real time, but is not penalized because they integrate over the hour).
Group
Duke Energy
Greg Rowland
Duke Energy
No
Duke Energy agrees that special provisions may be necessary to capture the combined BAAL performance of two BAs operating under a Supplemental Regulation agreement so that one BA can’t reset the 30-minute compliance clock of the other BA with a change to the dynamic interchange; however, we are concerned that these definitions could be interpreted to mean that three or more BAs could operate as one, sharing regulation, while the Standards lack sufficient detail behind how the associated interchange of such a group would be tagged or otherwise captured to ensure that the transmission impact is evaluated and subject to curtailment similar to other interchange. When a BA is formed from multiple BAs, its anticipated operation, impact on neighboring systems, and readiness to operate are evaluated – in some cases seams agreements have been required to address adjacent system concerns. The idea that multiple BAs could get together and form a Regulation Reserve Sharing Group (with the potential to impact neighboring systems no differently than is a single BA) without such scrutiny could have reliability implications. Regulation Reserve Sharing Group is not currently included in the NERC Functional Model. The process for registering such a group would have to be addressed for compliance. The words “regulating reserve” should be capitalized in the definition of RRSG.
Yes
Duke Energy has long supported the Field Trial of the Balancing Authority ACE Limit (BAAL) and supports its adoption in place of the current CPS2 as proposed in BAL-001-2.
Yes
Duke Energy does not support the definition of Reporting ACE as written. We believe that “ACE” should be defined as “The difference between the Balancing Authority’s net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error plus Automatic Time Error Correction (ATEC – If operating in the Western Interconnection and in the ATEC mode)”; followed with the equation shown and the details of the variables. “Reporting ACE” should be defined simply as the “The scan rate values of a Balancing Authority’s ACE”. Though Duke Energy supports the adoption of the BAAL; it’s not clear why all of the other changes to the standard are needed, nor is it clear how these changes respond to FERC directives. We believe that it should be mentioned that the BAAL addresses the FERC directive to develop a standard addressing the large loss of load – the BAAL measure will ensure appropriate response to any event causing the Balancing Authority’s ACE to exceed its BAAL (see comments to BAL-013 for further details). Duke Energy agrees with the proposed change to the BAAL equation to accommodate Time-Error Corrections by placing Scheduled Frequency in the numerator and denominator in place of 60 Hz; however it is not clear why Balancing Authorities under the Field Trial have not yet been afforded the opportunity to incorporate the same change in the BAAL calculation in their tools. Duke Energy would support allowing the Balancing Authorities under the Field Trial to make the appropriate changes in their tools to be consistent with the BAAL equation as

proposed, and would support the drafting team updating the tools on the NERC Field Trial website to be consistent with the current BAL-001-2 posted.
Individual
John Seelke
Public Service Enterprise Group
Agree
PJM Interconnection
Individual
Linda Horn
Wisconsin Electric Power Company
Agree
Midwest ISO
Individual
Don Jones
Texas Reliability Entity
Yes
1) The equation in the definition of Reporting ACE in the Standard is different than the one in the Implementation Plan (left off the WECC ATEC). 2) The Regulation Reserve Sharing Group Reporting ACE definition is different here than the Reserve Sharing Group Reporting ACE definition provided in BAL-002—which is correct? (Note “at the time of measurement” as last part of sentence)
1) The Implementation Plan does not include the WECC ATEC term. The ACE equation should be simplified so that it can apply to any interconnection. Any Time Error Correction term or alternate tertiary control term added to the ACE equation should enable any interconnection to control time error and reduce inadvertent interchange. 2) Attachment 2 also needs additional clarification regarding valid/invalid data. If a one-minute frequency sample is determined to not be valid, how is the 30 consecutive clock-minute count affected? Does the invalid minute count as an exceedance, or does the count ignore the invalid minute, or does the count start over at 0? 3) For Requirement R2, does there need to be an exclusion for the 30 consecutive clock-minute average if the BA experiences an EEA event or has a Balancing Contingency event within the 30 minute period? It seems feasible that if a BA experiences an EEA with extended low frequency or a Balancing Contingency event with an extended recovery period, that the clock-minute average for R2 might subsequently fail. Is this the intent of the SDT?
The latest changes to the VSLs for R2 made them more confusing. We would suggest re-wording them to state, for example: “The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes and for less than or equal to 45 consecutive clock minutes.”
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Agree
SERC OC Standards Review Group
Individual
Brian Murphy
NextEra Energy
Yes
The High Frequency Limit (FTLhigh) calculated as Fs + 3□1i should be changed to Fs + 4□1i
Individual
Robert Blohm
Keen Resources Ltd.
Yes
No
Yes

The Frequency Trigger Limit is set too tight at 3 standard deviations. This causes too many initial exceedences of BAAL as revealed in the field tests. This prompts BAs to wait until enough of them disappear by themselves to make it feasible to address all of the remainder. But, by waiting, the BA is failing to address the remainder early enough before they become outright violations. Instead, it would be better for reliability to raise the Frequency Trigger Limit to, say, 4 or 5 standard deviations to reduce the number of initial exceedences of BAAL to the point where it is feasible to address ALL of them immediately. What reliability is gained by a tighter limit that is feasible only if the BAs wait to address any and all of the exceedences? Furthermore, no legitimate statistical justification was ever provided for the tight 3-standard-deviations Frequency Trigger Limit. The very flawed attempt to provide such a justification led to rejection of the first version of this standard put out for balloting. No further formal technical justification was thereafter developed on which to base that or a wider limit, despite acknowledgement for a time on the drafting team that it was needed.
Individual
Bill Fowler
City of Tallahassee
Yes
No
This is not a yes/no question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today’s CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
No
this is not a yes/no question.
Individual
Karen Webb
City of Tallahassee
Yes
No
The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today’s CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
No
Individual
Scott Langston
City of Tallahassee
Yes
No
The question above is not a Yes/No question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today’s CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
No
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Services
Yes

N/A
LGE and KU Services is a participant in the BAAL Field Test and support the implementation of the BAAL standard
Group
FirstEnergy
Larry Raczkowski
FirstEnergy Corp
Agree
MISO
Group
Western Area Power Administration
Lloyd A. Linke
Western Area Power Administration
No
The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA's have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number of frequency excursions yet the participating BA's have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA' fully detune their AGC systems to take full advantage of the new requirements. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE – potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. The WECC experienced fewer instances where SOL were exceeded, when there was a ACE Transmission Limit of 4 times L sub 10 during the RBC Field Trial. Western recommends that the BARC SDT consider establishing an ACE Transmission Limit for the Western Interconnection. The impacts are not the same for Large Balancing Authorities as they are for small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001.
Group
MISO Standards Collaborators
Marie Knox
MISO
No
We don't understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control standard is referenced in the changes, RBC deals with a 30 minute limit on ACE and not redefinition of ACE and the creation of new entities.
Yes
Assuming we are wrong and that the drafting team has authority under their SAR or a specific FERC directive to modify the definitions in BAL-001, we have the following comments. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
No

Individual
Christopher Wood
Platte River Power Authority
Agree
Public Service Company of Colorado (Xcel Energy)
Individual
Spencer Tacke
Modesto Irrigation District
No
This concept violates the very definition of a balancing authority (control area).
Need a technical justification for the various Epsilon values specified.
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Southern Company Operations Compliance
Yes
Group
ERCOT
H. Steven Myers
ERCOT ISO
Yes
ERCOT ISO suggests that the drafting team consider adding the following language to the beginning of Requirement R2: The BAAL measure in R2 is a single event performance measurement similar to BAL-002-2 R1. BAL-002-2 R1 does not apply when a BA is in Emergency Alert Level 2 or 3. During EEA 2 or 3, priority should be given to returning the system to a secure state. Arguably this should exclusion should apply to all emergency conditions (EEA 1, EEA 2, and EEA 3). Consistent with the exclusion in BAL-002-2 R1, ERCOT suggests that the SDT consider adding the language below to BAL-001-2 R2: "'Except when an Energy Emergency Alert Level 2 or Level 3 is in effect' each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]" ERCOT ISO is voting "no" for the preceding reasons. However, if ERCOT ISO's proposed revisions are adopted, ERCOT ISO would support the standard.
Group
Powerex Corp.
Dan O'Hearn
Powerex Corp.
No
The proposed definitions have not been adequately justified for inclusion in the standard. The background document does not provide any additional information or reasons for inclusion of these definitions.
Powerex believes that the proposed draft standard is deficient in many respects as highlighted by commenters in the previous posting period. Specifically Powerex notes the following concerns in the proposed standard that highlight the inadequacy of the proposed requirements to uphold the reliability of interconnections. If these concerns are not adequately addressed the resultant standard could lead to degradation in reliability. The deficiencies include: 1) The

proposed standard allows for an entity to be outside of its BAAL limit for 29 minutes and be inside the limit for one minute, which provides a framework that allows an entity to possibly operate outside of the prescribed bounds 95 % of the time. The consequences of allowing such operations has not been adequately addressed by the drafting team, and allowing this standard to move forward with such latitude could lead to reliability issues. 2) The proposed standard does not restrict or limit BAs during periods of high congestion, when unscheduled flow on the entire system is causing reliability issues and/or exceedance of limits. Under the proposed standard the transmission path operators and BAs are forced to deal with unscheduled flows on the system without adequate tools or procedures in place to remedy the reliability events. During the field trial of the proposed standard these issues have been experienced in the WECC, where congestion management of non-Qualified and Qualified paths has created various operating issues for the entities and Reliability Coordinators. The consequences of allowing unlimited use of a transmission system via unlimited unscheduled flows, without better mechanisms to control flows, could lead to reliability events. The proposed standard does not provide the authority to the Reliability Coordinators to control and/or propose new operating procedures (eg. Limiting all BAs in the interconnection to operate within L10 during period of congestion) that mitigate unscheduled flows that are adversely impacting the transmission grid. This needs to be addressed in this proposed standard so that during high congestion periods, regardless of system frequency, BAs bring ACE limits within L10 or some other suitable limitation that decreases the adverse impact. 3) The proposed standard puts no limits on ACE during times of normal frequency, which allows BAs to inappropriately “lean” on other generation, or to push excessive amount of energy on to the transmission system. This deficiency allows a BA to obtain energy or push unscheduled energy across the interties during times that can be economically advantageous to the BA without regard to impacts upon neighboring BAs, load serving entities and transmission customers. It is paramount that the current standard, with CPS2, remain in place until such time that the reliability issues associated with the draft standard are resolved.
Powerex believes that the reliability issues with the current draft standard have not been adequately addressed by the drafting team. The reliability issues that have been previously submitted by commenters raised valid concerns, and the drafting team has not addressed those specific concerns in their responses. Powerex submits the following subsequent comments: 1) In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for inadvertent energy flows between adjacent BAs to both jeopardize reliability and to cause undue harm to customers on the grid. Such inadvertent energy flows are driven by the size of each BAAs ACE, but are primarily contained by CPS2 under the current BAL-001. FERC also made it clear that it was inappropriate for generators within a BAA to “dump power on the system or lean on other generation...The tiered imbalance penalties adopted in the Final Rule generally provide a sufficient incentive not to engage is such behavior” The proposed standard will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impacts and which could lead to exceedances in SOL due to large ACEs. The proposed performance standard does not address the potential for a single BA to lean on the grid with deliberate unscheduled energy flows or inadvertent energy, taking any accumulated benefits for itself and harming other entities on the grid. The detrimental impacts of deliberate inadvertent flows to load customers and transmission customers on the grid could be substantial when large ACE deviations cause transmission limit exceedances. It is imperative that the drafting team address this issue in the standard. 2) Various entities have also expressed concerns regarding the reliability impacts of inadvertent or unscheduled flows. The issues experienced by entities during the Field Trial were provided in the previous comment period, but the drafting team has failed to address the comments adequately. Furthermore, the drafting team ignored the concerns and provided a generic response to commenters from NE ISO, WECC, Tucson, APS, BPA and NPPD. These concerns regarding the BAAL standard include comments such as: a. Reliability concerns over BAAL limits not accounting for large ACE excursions b. Increase in transmission limit exceedances c. Interconnection exposed due to the lack of ACE bounding d. CPS 2 is a more reliable metric e. Allows for more unscheduled power flows and amount of unscheduled interchange a BA can have is not capped f. WECC average frequency deviation has been increasing g. Elimination of CPS2 has a detrimental impact on reliability h. Leads to transmission constraints and requires TOPs and RCs to restrict the unscheduled flows on the system due to a BA unilaterally over or under generating i. WECC has experienced many SOL violations due to Large ACEs 3) After reviewing the previous comments and responses, it has become abundantly clear that the drafting team chose to respond to commenters with generic statement such as “The drafting team conducts a monthly call to review the results from the BAAL field trial. There have not been any reliability issues raised by any RC during these calls. The drafting team encourages BA’s and RC’s to share any specific occurrences that they feel have reliability impacts as a result of operating under BAAL.”, but did not specifically address, revise or enhance the proposed standard based on the comments. These generic statements are not appropriate by a drafting team and could be considered as dismissive.. The drafting team seems to be suggesting that the “monthly call” mentioned in the drafting team’s response is the only forum where reliability concerns need to be addressed. As an example, WECC submitted comments and provided information on RC actions and asked for the drafting team to remedy the issue in the standard, and I quote “During Phase 3, the Reliability Coordinators (RC) reported several SOL exceedance associated with high ACE. The SOL exceedances were mitigated when RCs requested the high ACE value to be reduced to L10.The SDT must address transmission loading issues caused by high ACE.” The drafting team did not adequately address this issue, which was raised by a regional entity, and responded by issue a generic statement that since this issue wasn’t discussed on the monthly phone call that these issues or experiences in WECC are not true reliability issues. It is imperative that the drafting team revisit all those comments that have been received and make appropriate revisions, and additions to the standard address the reliability concerns raised by the entities regarding SOL exceedance, transmission loading, and unscheduled flow issues. 4) Powerex believes that the current field trial has not proven to be more reliable, and it is imperative that the issues surrounding the increases in frequency error, exceedance of SOL and transmission limits be addressed. There

has been no comparison or evidence provided that shows that the proposed standard is superior in reliability than CPS2. Several commenters have raised concerns with the elimination of CPS2, and impacts associated with the increase of frequency error and unscheduled interchange due to large ACE deviations, which pose a greater risk to reliability than the current CPS2 requirement. The drafting team cannot provide a generic statement that “BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability” without providing any evidence or data to test the validity of those statements. The drafting team has not provided any supporting evidence or data that would validate such a generic statement, nor has it provided any benefits that were realized during the field trial and resulted in enhanced reliability. On the contrary, WECC has experienced a degradation of reliability measures, impacts to commercial transmission customers, as well as reliability issues that required RC intervention during the field trial. Those detrimental effects of the proposed standard cannot be offset by the drafting team providing generic and unsupported statements. 5) Powerex believes that the standard should have a BAALHigh and BAALLow in place at all time in order to manage ACE deviations that may jeopardize reliability through unscheduled flows, which can lead to exceedance of SOL and transmission limits. For example, WECC membership found it appropriate to apply a limit of 4 times a BA’s L10. This mechanism provides flexibility to handle interconnection frequency while not allowing ACE deviations to become so significant that BA flows negatively impact the transmission system. 6) The drafting team stated in their response to previous comments that “The drafting team will be preparing a report based on the field trial results that will be posted prior to the FERC filing for this draft standard”. Powerex poses two questions to the drafting team: a) Why have the field trial results not been provided to NERC membership prior to ballot body? b) Why have the results for the field trial not been updated on the project page on the NERC website since June 2012? 7) The drafting team has not adequately addressed the issue of “sawtoothing” operations as exhibited by entities during the field trial. Sawtoothing can be described as entities that are allowing ACE to be unlimited for 29 minutes and then be brought under BAAL limits for 1 minute. This type of behavior is shown in the NERC reports posted on the field trial. The drafting team is hedging that entities will not operate in this manner after the field trial due to higher operation and compliance risk to entities. However, the NERC field trial should have created disincentives to not allow such behavior during the onset of the field trial, and requirements should have been adopted to discourage behavior that poses reliability risks.
Individual
Gregory Campoli
NYISO
Northeast Power Coordinating Council
No
The NYISO has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. It is not appropriate to indicate the SOL/IROL Standards will address these additional overloads as the flows that are causing the overloads due to the increase ACE are not identifiable in any contingency management system. We would propose dropping the BAAL calculation until a wider field trial could be conducted.
Group
ACES Standards Collaborators
Jason Marshall
ACES
No
(1) How does this standard “specifically preclude general improvements to PRC-005-2”? By introducing a new project for PRC-005, the entire standard is subject to revision. The previous standard could be modified and there are no scope restrictions to this project under the NERC Rules of Procedure. There is nothing to preclude changes to Protection Systems. The drafting team should be aware of these implications and reconsider the development of this project, as the last draft took almost seven years to gain industry approval. Further, the Commission has not even ruled on the pending standard, so there is still a tremendous amount of uncertainty as to whether any additional directives or modifications need to be made to PRC-005-2. (2) We have serious concerns with the new definitions being proposed in this draft standard. We feel this excessiveness terms are unnecessary when the standard is only adding a new type of device to an entity’s existing maintenance and testing procedure. (3) For example, the “Auto Reclosing” definition is vague and requires further interpretation. What does “such as anti-pump and ‘various’ interlock circuits” mean? “Various” is not a clear adjective to describe interlock circuits. We recommend revising the entire definition to clearly state the scope of the devices, or better yet, strike the definition from the standard. (4) The term “unresolved maintenance issue” is plain language with a common meaning, and therefore does not need to be introduced as a defined glossary term. This definition could lead to more zero defect compliance and enforcement treatment. What happens if a maintenance issue is not identified as unresolved? Shouldn’t a registered entity’s internal controls address these issues? Also, this term is missing the other half of the standard – the testing of these devices. It’s possible to have an unresolved testing issue as well. (5) The Commission set limitations on the autoreclosing devices that should

be included in Order No. 758. An autoreclosing relay should be tested and maintained, “if it either is used [1] in coordination with a Protection System to achieve or meet system performance requirements established in other Commission–approved Reliability Standards, or [2] can exacerbate fault conditions when not properly maintained and coordinated, then excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.” This is problematic because the primary purpose of reclosing relays is to allow more expeditious restoration of lost components of the system, not to maintain the reliability of the Bulk-Power System. This standard would improperly include many types of reclosing relays that do not necessarily affect the reliability of the Bulk-Power System. (6) Order No. 758 (P. 26), the Commission stated that “the standard should be modified, through the Reliability Standards development process, to provide the Transmission Owner, Generator Owner, and Distribution Provider with the discretion to include in a Protection System maintenance and testing program only those reclosing relays that the entity identifies as having an affect on the reliability of the Bulk-Power System.” (7) There are concerns with the supplementary reference document because it assumes that PRC-005-2 will be approved by the Commission. This assumption is misleading and should not reflect any Commission rulings that have yet to occur. We recommend stating the current status of the PRC-005-2 project, which was filed with FERC in February 2013 and is pending the Commission’s approval. Statements such as “PRC-005-2 ‘replaced’ PRC-011” should be modified to “PRC-005-2 will replace PRC-011 upon approval from FERC,” or something similar. (8) The drafting team stated that it reviewed the NERC System Analysis and Modeling Subcommittee (SAMS) “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.” SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent reclosing near a generating station subjects the generation station to severe fault stresses. This report is concluding that these devices do not result in a gap and do not affect the reliability of the Bulk-Power System, unless very specific circumstances arise as in the instance where reclosing relays are a part of an SPS scheme. This technical document does not support the development of the standard; rather, the report refutes the need to include these devices in the standard’s applicability.
No
(1) The SDT needs to clarify the implementation plan. The document is confusing because it focuses on the PRC-005-2 standard, which is not yet FERC-approved. This implementation plan is a constantly changing moving target. Why not wait until PRC-005-2 gets approved before initiating another project for the same standard? This would reduce some of the timing issues and confusion. (2) Why is the drafting team revising a standard that has not been approved by the Commission yet? The second version was only filed in February 2013, and the timing of this project is premature. It is quite possible that the Commission could remand or revise parts of the standard and issue other directives associated with the version 2, which would then need to be addressed. This project is untimely and should be postponed until there is a final order from FERC. At that point, there may be justification to continue with this project, expand the scope of the SAR to address any new directives that may be included in a final order of PRC-005-2, or to determine that a guidance document is an appropriate way to satisfy the FERC orders. (3) The Commission specifically advised the drafting team of PRC-005-2 to modify the standard to include reclosing relays. Because the drafting team did not include them during that opportunity, the drafting team should wait until a final order is issued. (4) Again, the drafting team needs to consider other methods of answering FERC directives. Not every directive needs to be addressed by developing or revising a standard. Adding reclosing relays to PRC-005 only complicates the most-violated non-CIP standard. There is enough concern about this standard already and the drafting team should consider alternative means to address the reclosing relay issue besides a standard revision. (5) This project contains similar timing issues as CIP version 4 and CIP version 5 because it is being developed prior to FERC issuing a final order on the previous version of the standard. The timing is problematic; registered entities will be forced to constantly be focusing on the next standard. The implementation plan should provide additional time, similar to PRC-005-2’s two intervals, to allow registered entities enough time to adjust their PSMT programs for Protection Systems, and then have additional time to adjust their PSMT plan and implement autoreclosers. (6) Thank you for the opportunity to comment.
No
Individual
John Bee on Behalf or Exelon and its Affiliates
Exelon
Yes
Exelon is basically fine with structure, but continues to have issues with frequency response measurement process, which compares current ACE to previous one minute avg. frequency. This creates a situation in which Real Time adjustments to generation dispatch might actually serve to hamper frequency support, rather than serve it.
Group
Tennessee Valley Authority

Dennis Chastain
Tennessee Valley Authority
Agree
SERC OC Standards Review Group
Group
Oklahoma Gas & Electric
Terri Pyle
Oklahoma Gas & Electric
Yes
No
While we appreciate the attempt to streamline and simplify the standard, the requirement of Balancing Authorities providing Overlap Regulation Service should be moved back into the requirements section. The Standard should be enforceable based solely on the Requirements. “The most critical element of a Reliability Standard is the Requirements. As NERC explains, “the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA.” If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.” (NOPR and Order 693)
No
Group
Luminant
Brenda Hampton
Luminant Energy Company LLC
Agree
Electric Reliability Council of Texas (ERCOT)
Group
IRC-SRC
Terry Bilke
MISO
No
We don’t understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project the need to change the definitions.
Unless there is justification we missed, the new definitions should be removed. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
Group
BC Hydro and Power Authority
Patricia Robertson
BC Hydro and Power Authority
No
BCHA applauds the significant improvement made in this proposed standard to add the term Reporting ACE and to create the definition for Regulation Reserve Sharing Group. However, BCHA respectfully submits the following reasons for its Negative vote: 1.The reliability impacts of increased unscheduled flow have not been adequately addressed. BC Hydro suggests studying in detail those events where a BA’s ACE was within BAAL however the Reliability Coordinator

still instructed the BAs to reduce ACE within L10 to mitigate path transmission loading issues. 2.There is no requirement for BAs to maintain their true load-resource balance, i.e. no requirement for ACE to cross zero during any predetermined scheduling period, or for the averaged ACE over any predetermined scheduling period to be within a reasonable limit about zero. The “base line” of zero-ACE for a true balance can be moved to as far away as the BAAL limit without any consequences to the BA as long the scheduled frequency is maintained (by other BAs with ACE in the opposite sign). Although there is more flexibility for BAs to deploy their resources and some potential benefit gained by reduced wear and tear cost, BAs may interpret BAAL as their rights to withhold their resource commitment. 3.Increased difficulties in the planning time frame for transmission use. The basis for setting aside the Transmission Reliability Margin might have to be revised to account for a wider range of ACE allowed by BAAL. This may lead to a larger transmission margin being made unavailable for commercial use. 4.Increased needs in real time for the RC to monitor SOL/IROL overloading and their instruction to BAs to scale back on ACE magnitude. This might be not practical for an Interconnection with multiple-RCs. It may also raise an inequity issue whereby not all BAs will be asked to refrain from operating with BAAL at the same time. 5.Potential for increased hidden operating costs to Transmission entities such as increased transmission losses caused by BAs exchanging their large imbalances without transmission rights.
Individual
Keith Morisette
Tacoma Power
Yes
Tacoma Power does not support the proposed standard. BAL-001 as proposed moves forward with a control standard that has not yet been fully vetted. Since the RBC field trial began in 2010, with a significant portion of WECC BA participation, results point to noteworthy reliability and market related issues. As the RBC allows larger BAs looser control (i.e. larger ACE values) and wider frequency values, the results include: increased coordinated phase shifter operations, dramatic increase in schedule curtailments due to unscheduled flow, frequency increasing in a negative direction during heavy load hours and positive direction during light load hours, increased manual time error corrections and hours of manual time error corrections and increasing inadvertent accumulations. All of these issues need time to be vetted by the industry and the proposed standard modified accordingly before Tacoma Power would support it.
Tacoma Power does not support a standard that institutionalizes a control methodology that is still in the development stage and is not supported by actual data. Thank you for consideration of our comments.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program
No
The definition of Regulation Reserve Sharing Group (RRSG) does not match the Applicability section. The above definition states that the pooled regulating reserves are used by the member balancing authorities to meet applicable regulating standards. I don’t think this is technically correct. The balancing authority that is a member of an RRSG basically transfers its obligations to the RSSG as Responsible Entity. The BA is only the Responsible Entity during periods where they are not in active status with the RRSG. Suggested rewording: End the sentence after the second occurrence of “Balancing Authorities” and delete “to use in meeting applicable regulating standards”. This may be sufficient but would probably be better if the following were added to the end: “When Balancing Authorities which are in active status and operating under the rules of an RRSG, the RRSG becomes the Responsible Entity for Standard Requirements related to Regulating Reserves for the member Balancing Authorities.
No
1. The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA’s have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number of frequency excursions yet the participating BA’s have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA’ fully detune their AGC systems to take full advantage of the new requirements. 2. The tools for managing path flows with respect to larger allowed deviations by participating BAs did not keep up with the RBC pilot. 3. BAL-001 is driven by economics, not reliability. It is easy to assess the $$$ gains by operating to BAAL, but the additional costs incurred to your Balancing Authority because of another Balancing Authority's operation within the BAAL envelope is

not easily calculated. Within NERC and in general, a system operating at 60 Hz is more reliable than one operating at some other value; however, there is no proof that the BAAL operating range is unreliable. Studies must be run on the WECC system with off-nominal frequency. This has been brought up in study team meetings, but the studies have yet to be performed. 4. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE – potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. 5. Any field trial results in addition to the limitations pointed out in 2. Above, are further tainted by the fact that not all BA’s are participating in the field trial. Only about 2/3rds of the total frequency bias of the Eastern Interconnection is represented by BA’s in the field trial. In the WECC that percentage is higher but it is known that not all of the “participating” BA’s have changed their control algorithms and for the BA’s that have; the magnitude of the control system changes are not known. 6. There are a variety of commercial issues being raised by entities familiar with the field trial. The issues range from transmission system flows and transmission rights being usurped by unscheduled flow to issue of imbalances being allowed to go into a BA’s ACE and Inadvertent Interchange balances. 7. Large Balancing Authorities benefit disproportionately to small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001. 8. There is no averaging of ACE, other than the one minute average used in the metric. This allows large deviations in ACE for prolonged periods of time, up to 29 minutes, without any adverse consequences to the BA with respect to this standard. 9. At this point in time BPA sees no simple solution to these issues. More information needs to be collected from Balancing Authorities taking part in the field trial and that information needs to be made more available to all interested parties. More extensive analysis needs to be done before any informed decisions can be made on this dramatic change to the control performance standards. 10 BPA believes that the analysis done during the field trials have been conducted with incomplete information, most notably they are lacking information on exactly what changes, if any, participating BA's have made to their control systems. 11 BPA believes that the proposed standard reduces the control performance measures by allowing "looser" control and is therefore, less stringent than the current standard, It is hard to understand how a loosening of the control performance standards can provide an increase in reliability.
No
Individual
Alice Ireland
Xcel Energy
Yes
Yes
1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. Xcel Energy believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. Xcel Energy is not asking for a change to the standard, just a clear statement for the purposes of documenting compliance.

Consideration of Comments

Project 2010-14.1 Phase I of Balancing Authority-based Controls: Reserves BAL-001-2

The Standard Drafting Team thanks all commenters who submitted comments on the BAL-001-2 standard. There were 55 sets of comments, including comments from approximately 178 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on industry comments the drafting team made the following clarifying modifications to the proposed standard and associated documents.

- Made clarifying changes to the proposed standard including adding the term "…in accordance with…" in Requirement R2.
- Made clarifying changes to the definition for Reporting ACE.
- Modified the effective date to allow for 12 months to prepare for compliance with BAAL.
- Corrected typographical errors in all documents.

There were a couple of minority issues that the team was unable to resolve, including the following:

- Many stakeholders felt that using BAAL could cause increased inadvertent flows and transmission issues. The drafting team explained that they had not seen any such issues described occur during the field trial that could be directly attributable to the use of BAAL. BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability.
- A couple of stakeholders were concerned that a small BAs operation could be more restrictive under BAAL. The drafting team stated that they were aware of the concern identified. However, the drafting team was attempting to develop a standard that would be applicable to the entire continent and did not know of any method to distinguish between larger and smaller BAs.
- A few stakeholders questioned the value of creating a Regulation Reserve Sharing Group. The drafting team explained that they did not want to rule out any tool that could be used to satisfy compliance within a standard. The drafting team was not mandating that a BA had to participate in a RRSG but could if it was determined to be in their best interest.
- One stakeholder expressed the need for an exemption from compliance during an EEA Level 1, 2, or 3 since they were a single BA Interconnection. The SDT explained that they discussed their concern but came to the conclusion that they did not believe that granting a exemption from compliance was in the best interest of reliability.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NExtEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Russel Mountjoy-Secretary	MRO NERC Standards Review Forum	X		X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5
2.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
5.	Jodi Jensen	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Lee Kittleson	OTP	MRO	1, 3, 5
8.	Marie Knowx	MISO	MRO	2
9.	Mike Brytowski	GRE	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10. Scott Bos	MPW	MRO	1, 3, 5, 6
11. Scott Nickels	RPU	MRO	4
12. Terry Harbour	MEC	MRO	1, 3, 5, 6
13. Tom Breene	WPS	MRO	3, 4, 5, 6
14. Tony Eddleman	NPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Robert Rhodes	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Allan George	Sunflower Electric Power Corporation	SPP	1
2. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
3. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4. Jerry McVey	Sunflower Electric Power Corporation	SPP	1
5. Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
6. Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Stuart Goza	SERC OC Standards Review Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jeff Harrison	AECI	SERC	1, 3, 5, 6
2. Ray Phillips	AMEA	SERC	4
3. David Jendras	Ameren	SERC	1, 3
4. Kevin Johnson	Big Rivers	SERC	1
5. Colby Brett Bellville	Duke	SERC	1, 3, 5, 6
6. Mike Lowman	Duke	SERC	1, 3, 5, 6
7. Tom Pruitt	Duke	SERC	1, 3, 5, 6
8. Jim Case	Enteregy	SERC	1, 3, 6
9. Phil Whitmer	Georgia Power Company	SERC	3
10. Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
11. Terry Bilke	MISO	SERC	2
12. Brad Gordon	PJM	SERC	2
13. Bill Thigpen	PowerSouth	SERC	1, 5
14. Tim Hattaway	Power South	SERC	1, 5
15. Sammy Roberts	Progress Energy	SERC	1, 3, 5, 6
16. Troy Blalock	SCE&G	SERC	1, 3, 5, 6

17. Glenn Stephens	SCPSA	SERC	1, 3, 5, 6
18. Rene Free	SCPSA	SERC	1, 3, 5, 6
19. Tom Abrams	SCPSA	SERC	1, 3, 5, 6
20. John Rembold	SIPC	SERC	1
21. Cindy Martin	Southern	SERC	1, 5
22. Jimmy Cummings	Southern	SERC	1, 5
23. Jimmy Cummings	Southern	SERC	1, 5
24. Randy Hubbert	Southern	SERC	1, 5
25. Kelly Casteel	TVA	SERC	1, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2. Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.		WECC	5
4. Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Lloyd A. Linke	Western Area Power Administration	X					X				

Additional Member	Additional Organization	Region	Segment Selection
1. Western Area Power Administration	Upper Great Plains Region	MRO	1, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
2.	Western Area Power Administration	Rocky Mouontain Region	WECC	1, 6
3.	Western Area Power Administration	Desert Southwest Region	WECC	1, 6
4.	Western Area Power Administration	Sierra Nevada Region	WECC	1, 6
5.	Western Area Power Administration	Colorado River Storage Project	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Marie Knox	MISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brein	NIPSCO	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	H. Steven Myers	ERCOT		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Morais	ERCOT	ERCOT	2
2.	Sandip Sharma	ERCOT	ERCOT	2
3.	Matt Stout	ERCOT	ERCOT	2
4.	Ken McIntyre	ERCOT	ERCOT	2
5.	Stephen Solis	ERCOT	ERCOT	2
6.	Vann Weldon	ERCOT	ERCOT	2
7.	Jeff Healy	ERCOT	ERCOT	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative	WECC	1
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
1. Terri Pyle	Oklahoma Gas & Electric	SPP	1										
2. Donald Hargrove	Oklahoma Gas & Electric	SPP	3										
3. Leo Staples	Oklahoma Gas & Electric	SPP	5										
15.	Group	Brenda Hampton	Luminant						X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Rick Terrill	Luminant Generation Company LLC	ERCOT	5										
16.	Group	Terry Bilke	IRC-SRC		X								
Additional Member	Additional Organization	Region	Segment Selection										
1. Stephanie Monzon	PJM	RFC	2										
2. Ben Li	IESO	NPCC	2										
3. Kathleen Goodman	ISONE	NPCC	2										
4. Charles Yeung	SPP	SPP	2										
5. Ali Miremadi	CAISO	WECC	2										
17.	Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X					
Additional Member	Additional Organization	Region	Segment Selection										
1. Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2										
2. Pat G. Harrington	BC Hydro and Power Authority	WECC	3										
3. Clement Ma	BC Hydro and Power Authority	WECC	5										
18.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Bart McManus		WECC	1										
2. Fran Halpin		WECC	5										
3. David Kirsch		WECC	1										
4. Ayodele Idowu		WECC	1										
5. Pam VanCalcar		WECC	5										
6. Don Watkins		WECC	1										
19.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				

Registered Ballot Body Segment: columns 1–10.

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Stephanie Monzon	PJM Interconnection, L.L.C		X								
23.	Individual	Pamela R. Hunter	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
24.	Individual	Dan O'Hearn	Powerex Corp.						X				
25.	Individual	Tom Siegrist	EnerVision, Inc.							X			
26.	Individual	John Tolo	Tucson Electric Power Co	X									
27.	Individual	Rich Hydzik	Avista	X		X		X					
28.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
31.	Individual	Jim Cyrulewski	JDRJC Associates LLC	X									
32.	Individual	Greg Travis	Idaho Power Company	X									
33.	Individual	Michael Falvo	Independent Electricity System Operator			X							
34.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
35.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
36.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								
40.	Individual	Thad Ness	American Electric Power	X		X		X	X				
41.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
42.	Individual	Linda Horn	Wisconsin Electric Power Company			X	X	X					
43.	Individual	Don Jones	Texas Reliability Entity										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
44.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
45.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
46.	Individual	Robert Blohm	Keen Resources Ltd.								X		
47.	Individual	Bill Fowler	City of Tallahassee			X							
48.	Individual	Karen Webb	City of Tallahassee					X					
49.	Individual	Scott Langston	City of Tallahassee	X									
50.	Individual	Christopher Wood	Platte River Power Authority	X		X		X	X				
51.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
52.	Individual	Gregory Campoli	NYISO		X								
53.	Individual	John Bee on Behalf or Exelon and its Affiliates	Exelon	X		X		X					
54.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
55.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of “Entity Name”
Luminant	Electric Reliability Council of Texas (ERCOT)
City of Austin dba Austin Energy	ERCOT
JDRJC Associates LLC	Midwest ISO
Wisconsin Electric Power Company	Midwest ISO
FirstEnergy	MISO
Alliant Energy	MRO NSRF
NYISO	Northeast Power Coordinating Council
Public Service Enterprise Group	PJM Interconnection
Platte River Power Authority	Public Service Company of Colorado (Xcel Energy)
Tennessee Valley Authority	SERC OC Standards Review Group
Entergy Services, Inc. (Transmission)	SERC OC Standards Review Group

1. **The BARC SDT has developed two new terms to be used with this standard. Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards. Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement. Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.**

Summary Consideration: Many of the commenters expressed concern that creating a Regulating Reserve Sharing Group conflicted with Reserve Sharing Group or was not clear in its use. The SDT explained that Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.

Several commenters questioned the need to create a definition for Reporting ACE. The SDT stated that the intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.

Some commenters stated that the Regulating Reserve Sharing Group was not in either the Functional Model or any NERC registry. The SDT explained that the Regulating Reserve Sharing Group would be added to the NERC Compliance Registry prior to implementation of this standard.

The majority of the commenters provided typographical corrections that needed to be made to the standard and its associated documents.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) How does this standard “specifically preclude general improvements

Organization	Yes or No	Question 1 Comment
		to PRC-005-2"? By introducing a new project for PRC-005, the entire standard is subject to revision. The previous standard could be modified and there are no scope restrictions to this project under the NERC Rules of Procedure. There is nothing to preclude changes to Protection Systems. The drafting team should be aware of these implications and reconsider the development of this project, as the last draft took almost seven years to gain industry approval. Further, the Commission has not even ruled on the pending standard, so there is still a tremendous amount of uncertainty as to whether any additional directives or modifications need to be made to PRC-005-2.(2) We have serious concerns with the new definitions being proposed in this draft standard. We feel this excessiveness terms are unnecessary when the standard is only adding a new type of device to an entity's existing maintenance and testing procedure.(3) For example, the "Auto Reclosing" definition is vague and requires further interpretation. What does "such as anti-pump and 'various' interlock circuits" mean? "Various" is not a clear adjective to describe interlock circuits. We recommend revising the entire definition to clearly state the scope of the devices, or better yet, strike the definition from the standard.(4) The term "unresolved maintenance issue" is plain language with a common meaning, and therefore does not need to be introduced as a defined glossary term. This definition could lead to more zero defect compliance and enforcement treatment. What happens if a maintenance issue is not identified as unresolved? Shouldn't a registered entity's internal controls address these issues? Also, this term is missing the other half of the standard - the testing of these devices. It's possible to have an unresolved testing issue as well. (5) The Commission set limitations on the autoreclosing devices that should be included in Order No. 758. An autoreclosing relay should be tested and maintained, "if it either is used [1] in coordination with a Protection System to achieve or meet system performance

Organization	Yes or No	Question 1 Comment
		requirements established in other Commission-approved Reliability Standards, or [2] can exacerbate fault conditions when not properly maintained and coordinated, then excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System." This is problematic because the primary purpose of reclosing relays is to allow more expeditious restoration of lost components of the system, not to maintain the reliability of the Bulk-Power System. This standard would improperly include many types of reclosing relays that do not necessarily affect the reliability of the Bulk-Power System.(6) Order No. 758 (P. 26), the Commission stated that "the standard should be modified, through the Reliability Standards development process, to provide the Transmission Owner, Generator Owner, and Distribution Provider with the discretion to include in a Protection System maintenance and testing program only those reclosing relays that the entity identifies as having an affect on the reliability of the Bulk-Power System." (7) There are concerns with the supplementary reference document because it assumes that PRC-005-2 will be approved by the Commission. This assumption is misleading and should not reflect any Commission rulings that have yet to occur. We recommend stating the current status of the PRC-005-2 project, which was filed with FERC in February 2013 and is pending the Commission's approval. Statements such as "PRC-005-2 'replaced' PRC-011" should be modified to "PRC-005-2 will replace PRC-011 upon approval from FERC," or something similar. (8) The drafting team stated that it reviewed the NERC System Analysis and Modeling Subcommittee (SAMS) "Considerations for Maintenance and Testing of Autoreclosing Schemes - November 2012." SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing malâ€performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent

Organization	Yes or No	Question 1 Comment
		reclosing near a generating station subjects the generation station to severe fault stresses. This report is concluding that these devices do not result in a gap and do not affect the reliability of the Bulkâ€Power System, unless very specific circumstances arise as in the instance where reclosing relays are a part of an SPS scheme. This technical document does not support the development of the standard; rather, the report refutes the need to include these devices in the standard's applicability.
Response: The BARC standards drafting team believes that this answer does not apply to the proposed BAL-001-2 standard.		
Duke Energy	No	Duke Energy agrees that special provisions may be necessary to capture the combined BAAL performance of two BAs operating under a Supplemental Regulation agreement so that one BA can't reset the 30-minute compliance clock of the other BA with a change to the dynamic interchange; however, we are concerned that these definitions could be interpreted to mean that three or more BAs could operate as one, sharing regulation, while the Standards lack sufficient detail behind how the associated interchange of such a group would be tagged or otherwise captured to ensure that the transmission impact is evaluated and subject to curtailment similar to other interchange. When a BA is formed from multiple BAs, its anticipated operation, impact on neighboring systems, and readiness to operate are evaluated - in some cases seams agreements have been required to address adjacent system concerns. The idea that multiple BAs could get together and form a Regulation Reserve Sharing Group (with the potential to impact neighboring systems no differently than is a single BA) without such scrutiny could have reliability implications. Regulation Reserve Sharing Group is not currently included in the NERC Functional Model. The process for registering such a group would have to be addressed for compliance. The words "regulating reserve" should be capitalized in the

Organization	Yes or No	Question 1 Comment
		definition of RRSG.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
American Electric Power	No	It is not clear what exact intent the drafting team has in the introduction of the term “Regulation Reserve Sharing Group”. This term is specified in the Applicability section, so is it the drafting team’s intent to propose that this new term be established as a new Functional Entity? If that is not the intent, we believe it is mistaken to specify any applicability to any grouping that does not have formal, registered members.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
PJM Interconnection, L.L.C	No	PJM disagrees with the Interconnection specific inclusion of IATEC in the Reporting ACE definition. The definition of ACE is internationally recognized. It is inappropriate for the SDT to change that definition because of one region in North America. PJM believes all Interconnections should adhere to a common ACE equation definition and that Interconnection specific differences should be addressed through development of a regional standard, as was BAL-004-WECC-01.
Response: The SDT appreciates your comments. The intent was to create a standard term for ACE that was flexible enough to		

Organization	Yes or No	Question 1 Comment
not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.		
Bonneville Power Administration	No	The definition of Regulation Reserve Sharing Group (RRSG) does not match the Applicability section. The above definition states that the pooled regulating reserves are used by the member balancing authorities to meet applicable regulating standards. I don't think this is technically correct. The balancing authority that is a member of an RRSG basically transfers its obligations to the RSSG as Responsible Entity. The BA is only the Responsible Entity during periods where they are not in active status with the RRSG. Suggested rewording: End the sentence after the second occurrence of "Balancing Authorities" and delete "to use in meeting applicable regulating standards". This may be sufficient but would probably be better if the following were added to the end: "When Balancing Authorities which are in active status and operating under the rules of an RRSG, the RRSG becomes the Responsible Entity for Standard Requirements related to Regulating Reserves for the member Balancing Authorities.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
Northeast Power Coordinating Council	No	The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new

Organization	Yes or No	Question 1 Comment
		terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term “RRSG” is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined “entities”. Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared through the FMWG.

Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The

Organization	Yes or No	Question 1 Comment
SDT has modified the definition to address concerns raised by the industry. **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
ISO New England Inc.	No	The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term “RRSG” is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined “entities”. Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared

Organization	Yes or No	Question 1 Comment
		through the FMWG.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. **The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
Powerex Corp.	No	The proposed definitions have not been adequately justified for inclusion in the standard. The background document does not provide any additional information or reasons for inclusion of these definitions.
Response: The SDT appreciates your comments. The SDT has developed these terms for the following reasons. **The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.**		
Modesto Irrigation District	No	This concept violates the very definition of a balancing authority (control area).
Response: The SDT appreciates your comments. Unfortunately, the SDT would need additional information to provide a response to your comment.		

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	We do not see the need to create these terms. We understand that the first term (RRSG) is used in the applicability section and arguable in R1. However, the proposed standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. Furthermore, since the term RRSG is in the applicability section of the standard, it implies that this is a new functional entity. In order for this term to have applicability, it needs to have defined roles. This definition should be vetted through the functional model working group and included in the functional model PRIOR to being included in BAL-001.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
MRO NERC Standards Review Forum	No	We don’t understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control

Organization	Yes or No	Question 1 Comment
		standard is referenced in the changes, RBC deals with a 30 minute limit on ACE and not redefinition of ACE and the creation of new entities.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. **The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.** **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
MISO Standards Collaborators	No	We don't understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control standard is referenced in the changes, RBC deals with a 30 minute limit on ACE and not redefinition of ACE and the creation of new entities.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within		

Organization	Yes or No	Question 1 Comment
a standard. The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
IRC-SRC	No	We don't understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project the need to change the definitions.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
SMUD	No	While the definitions are acceptable, terminology within the standards

Organization	Yes or No	Question 1 Comment
		that call these discrete entities would be better identified as an overarching Reserve Sharing Group that would encompass the various terms: RRSG, RRSGRA ect. Recommend replacing all unique terminology to only include the Reserve Sharing Group in the BAL-001.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
Texas Reliability Entity	Yes	1) The equation in the definition of Reporting ACE in the Standard is different than the one in the Implementation Plan (left off the WECC ATEC). 2) The Regulation Reserve Sharing Group Reporting ACE definition is different here than the Reserve Sharing Group Reporting ACE definition provided in BAL-002-which is correct? (Note “at the time of measurement” as last part of sentence)
Response: The SDT appreciates your comments. **1) The SDT has corrected this error.** **2) The SDT has corrected this and is now using a single term.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with the definitions, we have the following suggestions: (1) NIA (Actual Net Interchange) - capitalize the word ‘tie lines’ because it appears in the Glossary of Terms. (2) NIS (Scheduled Net Interchange) - capitalize the word ‘tie lines’

Organization	Yes or No	Question 1 Comment
		because it appears in the Glossary of Terms. Also, the words 'Net Interchange Actual' should be rewritten as 'Net Actual Interchange' and the word 'Interchange' de-capitalized in 'scheduled Interchange'. (3) Regulation Reserve Sharing Group - capitalize the word 'regulating-reserve' because it appears in the Glossary of Terms. Also, the '-' should be removed from 'regulating-reserve'. (4) Reporting ACE - capitalize the word 'net actual interchange'. Also, add 'net' to 'scheduled interchange' and capitalize, because definitions appear in the Glossary of Terms. (5) 10 - capitalize 'frequency bias setting'. (6) IME (Interchange Meter Error) - the words 'net interchange actual (NIA)' should be re-written as 'Net Actual Interchange' and capitalized. Also, de-capitalize the last instance of 'Interchange'. (7) IATEC (Automatic Time Error Correction) - capitalize the word interconnection'. (8) H - de-capitalize 'Hours' or is this a Clock Hour? (9) PIIaccum - capitalize the words 'interconnection', 'net interchange schedules', 'net interchange', and 'scheduled frequency'.

Response: Thank you for your comments.

1) **The SDT has made the correction that you have identified.**
2) **The SDT has made the correction that you have identified.**
3) **The SDT has made the correction that you have identified.**
4) **The SDT has made the correction that you have identified.**
5) **The SDT has made the correction that you have identified.**
6) **The SDT is purposely using "Net Interchange Actual" per the definition shown in the standard. The SDT has corrected the interchange.**

Organization	Yes or No	Question 1 Comment
7) **The SDT has made the correction that you have identified.** 8) **The SDT has made the correction that you have identified.** 9) **The SDT has made the correction that you have identified.**		
seattle city light	Yes	There are differing references to Regulating Reserve Sharing Group and Reserve Sharing Group between BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the Standards.
Response: The SDT appreciates your comments. The SDT has corrected this and is now using a single term.		
SERC OC Standards Review Group	Yes	We are concerned that the term "Reporting ACE" used in this definition has a different historic meaning than what is being formalized in this proposed standard. We recommend labeling this term as "Regulation Reporting ACE."
Response: The SDT appreciates your comments. The SDT is trying to provide a consistent measure of ACE to apply across all standards.		
SPP Standards Review Group	Yes	
PPL NERC Registered Affiliates	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Salt River Project	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power Co	Yes	
Avista	Yes	
Idaho Power Company	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
Keen Resources Ltd.	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	

2. **If you are not in support of this draft standard, what modifications do you believe need to be made in order for you to support the standard? Please list the issues and your proposed solution to them.**

Summary Consideration: Several commenters did not believe that the field trial had produced any positive results and that the Western Interconnection was experiencing problems associated with the use of BAAL. The SDT explained that BAAL had been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.

Some commenters felt that this standard was moving in the wrong direction and actually relaxing control performance. The SDT stated that the appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. If this is the case then there may be times when the value of reducing reliability is less than the savings resulting from reduced reliability. Taking any other view will result in inappropriate reliability decisions for the customers. The SDT further explained that they were focusing in on one of the measures of reliability which is frequency. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal.

Many commenters stated that there were unscheduled flow that created imbalances going in to a BAs ACE and Inadvertent Interchange Balances. The SDT responded that unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.

A few commenters expressed concern that the use of BAAL benefited larger users. The SDT explained that they were unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that

BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs.

A few other commenters felt that since there was no averaging of ACE (other than the one minute averaging within the metric) it would allow for large deviations in ACE for prolonged periods of time. The SDT stated that the reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.

A couple of commenters did not feel that the six month window prior to implementation of BAAL would allow sufficient time to prepare. The SDT stated that they agreed and modified the effective date to allow for a twelve month window to prepare for compliance.

A few commenters felt that creating a Regulating Reserve Sharing Group provided no benefit. The SDT explained that the SDT was not mandating that a BA had to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	(1) The SDT needs to clarify the implementation plan. The document is confusing because it focuses on the PRC-005-2 standard, which is not yet FERC-approved. This implementation plan is a constantly changing moving target. Why not wait until PRC-005-2 gets approved before initiating another project for the same standard? This would reduce some of the timing issues and confusion.(2) Why is the drafting team revising a standard that has not been approved by the Commission yet? The second version was only filed in February 2013, and the timing of this project is premature. It is quite possible that the Commission could remand or revise parts of the standard and issue other directives

Organization	Yes or No	Question 2 Comment
		associated with the version 2, which would then need to be addressed. This project is untimely and should be postponed until there is a final order from FERC. At that point, there may be justification to continue with this project, expand the scope of the SAR to address any new directives that may be included in a final order of PRC-005-2, or to determine that a guidance document is an appropriate way to satisfy the FERC orders.(3) The Commission specifically advised the drafting team of PRC-005-2 to modify the standard to include reclosing relays. Because the drafting team did not include them during that opportunity, the drafting team should wait until a final order is issued.(4) Again, the drafting team needs to consider other methods of answering FERC directives. Not every directive needs to be addressed by developing or revising a standard. Adding reclosing relays to PRC-005 only complicates the most-violated non-CIP standard. There is enough concern about this standard already and the drafting team should consider alternative means to address the reclosing relay issue besides a standard revision.(5) This project contains similar timing issues as CIP version 4 and CIP version 5 because it is being developed prior to FERC issuing a final order on the previous version of the standard. The timing is problematic; registered entities will be forced to constantly be focusing on the next standard. The implementation plan should provide additional time, similar to PRC-005-2's two intervals, to allow registered entities enough time to adjust their PSMT programs for Protection Systems, and then have additional time to adjust their PSMT plan and implement autoreclosers.(6) Thank you for the opportunity to comment.
Response: Thank you for your comment. Unfortunately, the comment you provided does not appear to address draft Standard BAL-001-2.		
Bonneville Power Administration	No	1. The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an

Organization	Yes or No	Question 2 Comment
		increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA's have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number of frequency excursions yet the participating BA's have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA' fully detune their AGC systems to take full advantage of the new requirements. 2. The tools for managing path flows with respect to larger allowed deviations by participating BAs did not keep up with the RBC pilot. 3. BAL-001 is driven by economics, not reliability. It is easy to assess the $$$ gains by operating to BAAL, but the additional costs incurred to your Balancing Authority because of another Balancing Authority's operation within the BAAL envelope is not easily calculated. Within NERC and in general, a system operating at 60 Hz is more reliable than one operating at some other value; however, there is no proof that the BAAL operating range is unreliable. Studies must be run on the WECC system with off-nominal frequency. This has been brought up in study team meetings, but the studies have yet to be performed. 4. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for

Organization	Yes or No	Question 2 Comment
		improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE - potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. 5. Any field trial results in addition to the limitations pointed out in 2. Above, are further tainted by the fact that not all BA’s are participating in the field trial. Only about 2/3rds of the total frequency bias of the Eastern Interconnection is represented by BA’s in the field trial. In the WECC that percentage is higher but it is known that not all of the “participating” BA’s have changed their control algorithms and for the BA’s that have; the magnitude of the control system changes are not known. 6. There are a variety of commercial issues being raised by entities familiar with the field trial. The issues range from transmission system flows and transmission rights being usurped by unscheduled flow to issue of imbalances being allowed to go into a BA’s ACE and Inadvertent Interchange balances. 7. Large Balancing Authorities benefit disproportionately to small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001. 8. There is no averaging of ACE, other than the one minute average used in the metric. This allows large deviations in ACE for prolonged periods of time, up to 29 minutes, without any adverse consequences to the BA with respect to this standard.

Organization	Yes or No	Question 2 Comment
		9. At this point in time BPA sees no simple solution to these issues. More information needs to be collected from Balancing Authorities taking part in the field trial and that information needs to be made more available to all interested parties. More extensive analysis needs to be done before any informed decisions can be made on this dramatic change to the control performance standards. 10. BPA believes that the analysis done during the field trials have been conducted with incomplete information, most notably they are lacking information on exactly what changes, if any, participating BA's have made to their control systems. 11. BPA believes that the proposed standard reduces the control performance measures by allowing "looser" control and is therefore, less stringent than the current standard, It is hard to understand how a loosening of the control performance standards can provide an increase in reliability.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**
2. **Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL but was not adopted by the WECC.**
3. **All reliability standards have some economic component. The goal is to balance the economic cost with the reliability cost to**

Organization	Yes or No	Question 2 Comment
		achieve the best joint reliability/economic result. Studies performed for FERC indicate that the WECC in general is spending more for secondary frequency control and less for primary frequency control that is economically justified. The SDT believes that BAAL provides the BA with the correct reliability factor, being Frequency, and allows for the coordination among the BAs to move frequency in the correct direction for the reliability of the Interconnection. 4. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. 5. Non-participation in a voluntary field trial is not a reason for delaying the implementation of a standard. Field Trials are held for the express purpose of determining whether there are any problems that will arise if the new standard is implemented. The function of NERC is not to tell each BA how to operate their unique portion of the BES, but is instead to set boundaries that define the limits of reliable operations and allow each BA to operate freely within those limits. 6. Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading. 7. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs. 8. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded. 9. The SDT posts monthly the available information on the field trial to the NERC website. WECC elected not to release the detailed data from the field trial. The BARC SDT believes eight years of study of these issues is sufficient to make an informed decision. 10. Results based standards provide measureable limits that define reliable operations. Results based standards should not require information about how those results are achieved. They should require only the measured results demonstrate reliable operations. In a results based standard environment, it is inappropriate to judge how the results are achieved; only

Organization	Yes or No	Question 2 Comment
they are achieved and they will result in an appropriate level of reliability. 11. The SDT is focusing in on one of the measures of reliability which is frequency. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. Please refer to responses to 3 and 4 above.		
BC Hydro and Power Authority	No	BCHA applauds the significant improvement made in this proposed standard to add the term Reporting ACE and to create the definition for Regulation Reserve Sharing Group. However, BCHA respectfully submits the following reasons for its Negative vote: 1. The reliability impacts of increased unscheduled flow have not been adequately addressed. BC Hydro suggests studying in detail those events where a BA's ACE was within BAAL however the Reliability Coordinator still instructed the BAs to reduce ACE within L10 to mitigate path transmission loading issues. 2. There is no requirement for BAs to maintain their true load-resource balance, i.e. no requirement for ACE to cross zero during any predetermined scheduling period, or for the averaged ACE over any predetermined scheduling period to be within a reasonable limit about zero. The "base line" of zero-ACE for a true balance can be moved to as far away as the BAAL limit without any consequences to the BA as long the scheduled frequency is maintained (by other BAs with ACE in the opposite sign). Although there is more flexibility for BAs to deploy their resources and some potential benefit gained by reduced wear and tear cost, BAs may interpret BAAL as their rights to withhold their resource commitment. 3. Increased difficulties in the planning time frame for transmission use. The basis for setting aside the Transmission Reliability Margin might have to be revised to account for a wider range of ACE allowed by BAAL. This may lead to a larger transmission margin being made unavailable

Organization	Yes or No	Question 2 Comment
		for commercial use. 4. Increased needs in real time for the RC to monitor SOL/IROL overloading and their instruction to BAs to scale back on ACE magnitude. This might be not practical for an Interconnection with multiple-RCs. It may also raise an inequity issue whereby not all BAs will be asked to refrain from operating with BAAL at the same time. 5. Potential for increased hidden operating costs to Transmission entities such as increased transmission losses caused by BAs exchanging their large imbalances without transmission rights.

Response: Thank you for your comments.

1. **Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL that could be used to determine contribution to path flows. ACE is not a definitive measure of reliability.**
2. **It is impossible for any BA on a multiple BA interconnection to maintain their load-resource balance (zero ACE) at all times. Therefore, the standard sets limits with respect to how much ACE deviation can be allowed during reliable operations. Even CPS2 does not require a long-term average of ACE that is close to zero. There is no reliability consequence associated with average ACE deviation as calculated for CPS2. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.**
3. **The appropriate goal for NERC in standards development should be more than to merely improve reliability; it should also consider whether reliability levels are set such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. As long as the cost of different Transmission Reliability Margin is included in the cost benefit determination of the appropriate level of reliability, the inclusion of the change in Transmission Reliability Margin is appropriate. Taking any other view will result in inappropriate reliability decisions for the customers.**
4. **The WECC study indicated that ACE deviations were as likely to result in decreases in transmission path loading as to result in**

Organization	Yes or No	Question 2 Comment
increases in transmission path loading. The logic presented would be justification not to allow any changes in operations because they might result in these same problems yet changes are made in operations often. During the field trial the SDT has not had any Eastern Interconnection RC identify any issues as you describe. 5. The SDT believes that transmission losses are almost as likely to move upward as they are to move downward. Tightening balancing control standards to address transmission issues is an inappropriate reason to restrict control which can significantly increase costs for everybody.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative due to the “Regulation Reserve Sharing Group” being an applicable Entity and the fact that there is no functional or Registered Entity defined as a “Regulation Reserve Sharing Group”. Absent any Entities registered as a “Regulation Reserve Sharing Group”, compliance cannot be assessed against this entity, thus making any requirements applicable to the “Regulation Reserve Sharing Group” unenforceable.
Response: Thank you for your comments. The SDT will have the Regulation Reserve Sharing Group added to the compliance registry once this standard has been approved by the industry and FERC.		
seattle city light	No	Seattle City Light supports the implementation of BAAL limits to replace CPS2, but think this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Specifically, Seattle experienced good results in the Reliability Based Controls field trials and supports the RACE and BAAL concepts. However, Seattle has concerns about the compliance risk introduced by the many new definitions and new types of reserve sharing groups proposed under this draft. In particular are the relations among Regulation Reserve Sharing Group, Reserve Sharing Group, and Balancing Authority ability to designate one or another of these groups as responsible entity. For example, as currently written there may be a possibility of conflict between the applicability of BAL-001-2 and Requirement R2 of the

Organization	Yes or No	Question 2 Comment
		Standard. As written Applicability Section 4.0 states the Standard is applicable to: 4.1 Balancing Authority 4.1.2 A balancing Authority that is a member of Regulation Reserve Sharing Group is the Responsible Entity only in period during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Regulation Reserve Sharing Group. 4.2. Regulation Reserve Sharing Group. Further Requirement R2 of the Standard states that: R2. Each Balancing Authority shall operate such that its clockâ€minute average of ReportingACE does not exceed its clockâ€minute Balancing Authority ACE Limit (BAAL) for morethan 30 consecutive clockâ€minutes, as calculated in Attachment 2, for the applicableInterconnection in which the Balancing Authority operates.[Violation Risk Factor:Medium] [Time Horizon: Realâ€time Operations]Seattle finds the Standard is not clear if requirement R.2 is applicable to the Regulation Reserve Sharing Group as a group or to all BAs individually participating in Regulation Reserve Sharing Group. As currently written a BA can argue that R.2 is not applicable if they are participating in Regulation Reserve Sharing Group, and Seattle is not sure if this was the intent of the Standard Drafting Team. Another example is that Attachment 1 used to describe how to calculate CPS1 does not appear to be complete. It needs to be revised to include the methodology for calculating the CPS1 for the Regulation Reserve Sharing Group. Seattle is also concerned that BAL-001-2 R2 “...more than 30 consecutive clock-minutes...” requirement represents too long a time, and should be changed to a shorter time frame to better reflect the existing and proposed sub-hour scheduling windows and other Standards limiting the time that a Balancing Authority is not positively supporting system

Organization	Yes or No	Question 2 Comment
		frequency.
Response: Thank you for your comments. **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.** **The SDT has not seen any issues arise during the field trial concerning the 30 clock-minute time window. In addition, the SDT believes that this is complementary with time limits established in transmission related standards. The SDT received no other comments concerning the 30 clock-minute duration for BAAL and believes that it is appropriate.**		
Nebraska Public Power District	No	The applicability section of the standard allows for periods of time when a BA may be responsible for meeting the requirements of this standard and times when a Regulation Reserve Sharing Group may be responsible for meeting the requirements of this standard. However R1 requires calculating a 12 month average CPS 1. Neither the requirement nor the attachment address how a responsible entity is to handle those periods, which may be portions of a month, day or hour when they are not responsible for meeting the requirements. If the period is to be treated as bad data, the standard or attachment that details the calculation needs to specify how those periods are handled. The term “active status” used in section 4.1.2 is not a defined term and may not be included in any regulation reserve sharing agreements. There should be more clarity around this term. Given the concerns noted above, are there minimum time periods when a regulation reserve sharing group may not be in “active status”. For example, can a regulation reserve sharing pool be inactive for a portion of an hour, or conversely only be active for a portion of the hour? The standard needs more clarification on what active status means and how frequently the status can change.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT included the possibility of active versus inactive status for the potential of events such as, but not limited to telemetry failure.**		
City of Tallahassee	No	The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. **The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.**		
Western Area Power Administration	No	The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA's have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number

Organization	Yes or No	Question 2 Comment
		of frequency excursions yet the participating BA's have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA' fully detune their AGC systems to take full advantage of the new requirements. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE - potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. The WECC experienced fewer instances where SOL were exceeded, when there was a ACE Transmission Limit of 4 times L sub 10 during the RBC Field Trial. Western recommends that the BARC SDT consider establishing an ACE Transmission Limit for the Western Interconnection. The impacts are not the same for Large Balancing Authorities as they are for small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration**

Organization	Yes or No	Question 2 Comment
approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL. 2. Results based standards provide measureable limits that define reliable operations. Results based standards should not require information about how those results are achieved. They should require only the measured results demonstrate reliable operations. In a results based standard environment, it is inappropriate to judge how the results are achieved; only they are achieved and they will result in an appropriate level of reliability. 3. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. 4. The Eastern Interconnection has not experienced increases in SOL exceedances that were attributed to the Field Trial; therefore, any fixed ACE Transmission Limit would be inappropriate to add to a continent wide standard. 5. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs.		
NYISO	No	The NYISO has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. It is not appropriate to indicate the SOL/IROL Standards will address these additional overloads as the flows that are causing the overloads due to the increase ACE are not identifiable in any contingency management system. We would propose dropping the BAAL calculation until a wider field trial could be conducted.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The SDT believes that BAAL provides the BA with the correct reliability factor and allows for the coordination among the BAs to move frequency in the correct direction for the reliability of the Interconnection. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. The SDT has focused on frequency as the measure of reliability for this standard. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. It is the opinion of the SDT that conducting a wider field trial beyond what was conducted in the West, which involved 70% of the BAs, would not provide any additional benefit. Sufficient data exists to support that reliability is not degraded. The SDT believes that the implementation of BAAL as an enforceable standard would result in similar system performance as it relates to transmission flows as presently achieved with CPS 2.		
City of Tallahassee	No	The question above is not a Yes/No question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.		
Avista	No	The RBC Field Trial in the WECC provided enough information to determine if RBC had any effects on reliability. The WECC PWG's July 2012 report to the WECC OC clearly documented frequency error was increasing over previous operation under CPS2. It documented increasing frequency in the negative direction in heavy load hours (particularly morning and evening peaks) and increasing frequency error

Organization	Yes or No	Question 2 Comment
		in the positive direction during light load hours. This report also shows Epsilon 1 and Epsilon 10 increasing significantly over past CPS2 performance years. Manual time error corrections and hours of manual time error corrections are approximately double what they had been. The PWG report documents increasing unscheduled flow events with the ACE Transmission Limit (ATL) being increased or eliminated. This has continued on into 2013. This indicates that RBC has a negative effect on path flow control and management. Increasing inadvertent accumulations are also documented in the PWG report. Increasing inadvertent, unscheduled flow events and curtailments, and prolonged frequency deviations beyond 0.030 Hz are not hallmarks of a reliable system. No studies, or actual events, have demonstrated that the WECC system can perform for a 2800 MW (G-2) generation loss with an initial frequency of 59.94 Hz or lower. Additional control problems are created when frequency deviations beyond 0.030 Hz occur, exceeding governor deadband on generating units (IEEE standard deadband). If these units are being used for Automatic Generation Control (AGC), they will move to governor control, generally disabling the AGC functionality. This does not add to system reliability, and likely detracts from it. The RBC formula advantages larger Balancing Authorities by allowing looser control and wider frequency ranges. Whereas a smaller BA may see the BAAL limits quickly shrink at deviations near 0.050 Hz, a larger BA can still run a large ACE, creating inadvertent flow and secondary control problems for smaller BA's. Finally, loose ACE control effectively eliminates the effectiveness of the WECC Automatic Time Error Correction system. WECC ATEC depends on

Organization	Yes or No	Question 2 Comment
		CPS2 compliance in order to ensure that a BA is continuously paying back its accumulated Primary Inadvertent balance. With the loose limits of RBC, the Primary Inadvertent payback term is small enough that it may not even influence the BA's AGC control algorithm. This can be clearly seen by the increasing WECC frequency deviation beginning with the field trial in 2010. ATEC was implemented in WECC in 2003, and low frequency deviation from 2003-2009 is easily seen the PWG 2012 WECC OC report. R2 is not a frequency control requirement under all conditions, it is a requirement that is used under normal conditions. It is designed to operate around small frequency deviations. For large frequency deviations, frequency support is required and measured by ACE recovery under BAL-002 (DCS). With respect to R2/M2, how many times can a BA exceed BAAL limits for 30 minutes? Can a BA exceed BAAL for 27 minutes every hour? A limit based on so many minutes exceeding BAAL per month or some similar measure may be more likely to incent the desired control performance. How do you measure severity if an event happens many times, but never exceeds 30 minutes? Is 29 minutes ok and 31 minutes a risk to the interconnection? Comments: "BAL-001-1 Real Power Balancing Control Standard Background Document" Page 4 has an illuminating statement."CPS2 is: Designed to limit a Control Area's (now BA) unscheduled power flow." This is a significant issue in the WECC. Unscheduled power flow becomes unmanageable without the CPS2 requirement. There is no other way to control BA to BA power flow if a BA is not required to maintain its Net Actual Interchange within a limit. The summary statement on page 6 is not supported by the field trials. The summary statement says that RBC improves upon CPS2 by

Organization	Yes or No	Question 2 Comment
		dynamically altering ACE limits based on frequency. The WECC field trial conclusively demonstrates that frequency control is worse and frequency error is greater, indicating RBC decreases reliability compared to CPS2. The inability to control path flows effectively, requiring unscheduled flow mitigation to remain within System Operating Limits, inherently decreases reliable operation. CPS2 takes frequency into account with the frequency component of the ACE equation. To claim that operating to the ACE equation does not inherently support system frequency is not logical. The CPS2 requirement should be retained, and the BAAL should not be adopted.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**
2. **The WECC Unscheduled Flow Administrative Subcommittee (UFAS) evaluation of 2012 events showed the BAAL to be a relatively minor issue in regards to the events seen. The PWG evaluation was less in depth than the UFAS evaluation.**
3. **As the Interconnection approaches lower frequencies such as 59.94 Hz, BAAL will provide the BA direction to return their ACE closer to zero; whereas CPS2 does not provide the same guidance.**
4. **While ASME had a 36 mHz standard (PTC 20.1-1977 Speed and Load Governing Systems for Steam Generating Units) until 2003, it is no longer a part of any recognized standard of IEEE, ASME or NERC to the knowledge of this SDT. All frequency control results in normal distributions of frequency error. This has been demonstrated on all of the North American Interconnections. Looser ACE control will not eliminate the effectiveness of the WECC ATEC system because the frequency error will still be normally distributed around scheduled frequency. The effectiveness of the inadvertent payback will also**

Organization	Yes or No	Question 2 Comment
continue. AGC should continue to function normally even when units are outside of the deadband. 5. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs. 6. All frequency control results in normal distributions of frequency error. This has been demonstrated on all of the North American Interconnections. Looser ACE control will not eliminate the effectiveness of the WECC ATEC system because the frequency error will still be normally distributed around scheduled frequency. The effectiveness of the inadvertent payback will also continue. 7. The BAAL is applicable every minute of every day. Exceeding the BAAL for more than 30 clock-minutes will be a violation regardless of frequency level. 8. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater the individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded. 9. Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading. 10. The SDT has focused on frequency as the measure of reliability for this standard. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. 11. It is correct that CPS2 is affected by frequency through the ACE equation, but the commenter failed to realize that the 10 minute average required in the CPS2 measure can be detrimental to frequency because an average can incent behavior that causes control actions that make frequency worse instead of better.		
City of Tallahassee	No	This is not a yes/no question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting

Organization	Yes or No	Question 2 Comment
		Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.		
Northeast Power Coordinating Council	No	We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.
Response: Thank you for your comments. **The SDT has eliminated the term RRSG Reporting ACE.** **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.** **The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.**		
ISO New England Inc.	No	We do not see the need to create the two new terms (RRSG and RRSG

Organization	Yes or No	Question 2 Comment
		Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG.The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.
Response: Thank you for your comments. **The SDT has eliminated the term RRSG Reporting ACE.** **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.** **The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.**		
Oklahoma Gas & Electric	No	While we appreciate the attempt to streamline and simplify the standard, the requirement of Balancing Authorities providing Overlap Regulation Service should be moved back into the requirements section. The Standard should be enforceable based solely on the Requirements."The most critical element of a Reliability Standard is the Requirements. As NERC explains, "the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA." If

Organization	Yes or No	Question 2 Comment
		properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.” (NOPR and Order 693)
Response: Thank you for your comments. **Based on conversations with NERC staff, the SDT moved the requirement concerning Overlap Regulation Service to the applicability section. The SDT, as well as NERC staff, did not believe that this should be a requirement.**		
Independent Electricity System Operator	No	While we do not see the need to create the two new terms (RRSG and TTSG Reporting ACE), if the terms were to be included, the term RRSG should be vetted through the functional model working group PRIOR to including it in this standard as it appears to be a new functional entity. As such, it’s roles should be defined in the functional model prior to being incorporated into any NERC standards.We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG.We generally supported the previous draft that stipulates the requirements for each BA. We are unable to support the currently posted version as it appears to place requirements on both individual BAs and the RRSG but the obligations for the latter is not clearly stipulated in the standard. At any rate, we do we see a need to have that latter (RRSG) requirements stipulated for the RRSG so long as the standard places obligation to each BA to meet the CPS1 and BAAL requirements.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The SDT has eliminated the term RRSG Reporting ACE.** **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.** **The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.**		
SPP Standards Review Group	No	With the introduction of the Regulating Reserve Sharing Group there appears to be a registration gap. There currently isn't a Regulating Reserve Sharing Group entity in the Functional Model. It would appear that such a registration would have to be made in order to be able to hold the Regulation Reserve Sharing Group accountable for compliance purposes. Providing this is done, then R1 and R2 should reflect the applicability to both the Balancing Authority and the Regulation Reserve Sharing Group. As written R1 requires any applicable BA to maintain CPS1 for the Interconnection within which it operates at 100 percent or higher. The rolling 12-month calculation needs additional clarification also. We suggest the requirement should be rewritten to read:The Responsible Entity shall operate such that its Control Performance Standard 1 (CPS1), calculated based on the applicable Interconnection in which it operates in accordance with Attachment 1, is greater than or equal to 100 percent for each consecutive 12-month period. Each consecutive 12-month period shall be evaluated monthly. As written, R2 applies only to a Balancing Authority. It should be reworded to apply to both a Balancing Authority or Regulation Reserve Sharing Group as is R1. Substitute Responsible Entity for Balancing

Organization	Yes or No	Question 2 Comment
		Authority in the requirement. Likewise we would suggest deleting the comma following 'Attachment 2' in R2. This links the ending phrase of the sentence to the calculation, where it should be, more tightly. In the last line of Attachment 2, insert 'Overlap' in front of 'Regulation Service'.
Response: Thank you for your comments. **The Regulation Reserve3 Sharing Group will be added to the Compliance Registry prior to the standard going into effect.** **The SDT has added clarifying language to Requirement R1 to address your concern.** **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.** **The SDT believes that the current writing of Requirement R2 is correct and provides the necessary clarity.** **The SDT has added the word "Overlap" as you suggested.**		
Keen Resources Ltd.	No	
Manitoba Hydro	Yes	Although Manitoba Hydro is in support of the standard, we have the following clarifying suggestions: (1) (Proposed) Effective Date in both the Standard and Implementation Plan - remove the " ' " following the word 'Trustees' because it is not defined this way in the Glossary of Terms. (2) Applicability 4.1.2 - add an 's' on the end of the word 'period'. In addition, add the word 'the' before 'governing rules'. (3) Data Retention - capitalize three instances of 'compliance enforcement authority' in this section.

Organization	Yes or No	Question 2 Comment
		(4) R1 - the words '12 month period' should be changed to 'rolling 12 month basis' for consistency with the VSL table. (5) R1 - for clarity, 'it' should be specified as the 'Responsible Entity'. (6) R2/M2 - please clarify if this requirement/measure should refer only to Balancing Authority as opposed to Responsible Entity? (7) R2 - add the words 'accordance with' before 'Attachment 2'. (8) M1, M2 - the term 'Energy Management System' is not found in the Glossary and should be defined. (9) VSL, R2 and Attachment 1, CPS1 - add a '-' between the words 'clock minutes' for consistency with the standard. In addition, the words 'for the applicable Interconnection' should be added for consistency with the language of R2 and the VSL for R1. (10) General - there is inconsistency throughout the standard and Attachments with respect to the following words: '12 month period', 'rolling 12 month basis', '12-calendar months', '12-month'. We suggest selecting one of these terms and using it throughout the standard and attachments.

Response: Thank you for your comments.

1) **The SDT has made the modification as requested.**
2) **The SDT has made the modification as requested.**
3) **The SDT has made the modification as requested.**
4) **The SDT has added clarifying language to the requirement.**
5) **The SDT believes that the use of the word "it" provides the necessary clarity.**
6) **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.**
7) **The SDT has made the modification as requested.**

Organization	Yes or No	Question 2 Comment
8) The SDT has removed the term "Energy Management System". 9) The SDT has made the modification as requested. 10) The SDT has corrected the inconsistency that you have described.		
MISO Standards Collaborators	Yes	Assuming we are wrong and that the drafting team has authority under their SAR or a specific FERC directive to modify the definitions in BAL-001, we have the following comments. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
Response: Thank you for your comments. **The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.**		
Duke Energy	Yes	Duke Energy has long supported the Field Trial of the Balancing Authority ACE Limit (BAAL) and supports its adoption in place of the current CPS2 as proposed in BAL-001-2.
Response: Thank you for your comments.		
Salt River Project	Yes	There is reasonable concern that the large ACE values that the standard permits under certain conditions will cause excessive unscheduled flow on qualified transmission paths. We believe that this issue can be

Organization	Yes or No	Question 2 Comment
		managed by the Reliability Coordinator through enforcement of existing standards, but may require changes to current practices.
Response: Thank you for your comments.		
EnerVision, Inc.	Yes	
Tucson Electric Power Co	Yes	
Energy Mark, Inc.	Yes	
Texas Reliability Entity		1) The Implementation Plan does not include the WECC ATEC term. The ACE equation should be simplified so that it can apply to any interconnection. Any Time Error Correction term or alternate tertiary control term added to the ACE equation should enable any interconnection to control time error and reduce inadvertent interchange. 2) Attachment 2 also needs additional clarification regarding valid/invalid data. If a one-minute frequency sample is determined to not be valid, how is the 30 consecutive clock-minute count affected? Does the invalid minute count as an exceedance, or does the count ignore the invalid minute, or does the count start over at 0? 3) For Requirement R2, does there need to be an exclusion for the 30 consecutive clock-minute average if the BA experiences an EEA event or has a Balancing Contingency event within the 30 minute period? It seems feasible that if a BA experiences an EEA with extended low frequency or a Balancing Contingency event with an extended recovery period, that the clock-minute average for R2 might subsequently fail. Is this the intent of the SDT?

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1) The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **2) The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.** **3) The SDT discussed this issue in great detail. The SDT decided that it would not be in the best interest of reliability to grant any exceptions.**		
American Electric Power		AEP has suggested modifications regarding scope and content in our responses to Q1 & Q3. Most concerning to us are the topics raised in our response to Q3 (below).
Response: Thank you for your comment. Please refer to our responses above.		
MRO NERC Standards Review Forum		Assuming we are wrong and that the drafting team has authority under their SAR to modify BAL-001, we have the following comments. 1) Unless there is justification we missed, the new definitions should be removed. 2) With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Tertiary Control. (Alternatively, clarify that IATEC is equal to ITC. This way the reporting and operating number would be the same.) The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their dead-bands under BAL-003-1.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1 – The SDT believes that the new definitions are needed to provide necessary clarity for the standard.** **2 – The SDT has modified the definition for Reporting ACE based on the collective comments from the industry.**		
ERCOT		ERCOT ISO suggests that the drafting team consider adding the following language to the beginning of Requirement R2: The BAAL measure in R2 is a single event performance measurement similar to BAL-002-2 R1. BAL-002-2 R1 does not apply when a BA is in Emergency Alert Level 2 or 3. During EEA 2 or 3, priority should be given to returning the system to a secure state. Arguably this should exclusion should apply to all emergency conditions (EEA 1, EEA 2, and EEA 3). Consistent with the exclusion in BAL-002-2 R1, ERCOT suggests that the SDT consider adding the language below to BAL-001-2 R2:"'Except when an Energy Emergency Alert Level 2 or Level 3 is in effect' each Balancing Authorty shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]"ERCOT ISO is voting "no" for the preceding reasons. However, if ERCOT ISO's proposed revisions are adopted, ERCOT ISO would support the standard.
Response: Thank you for your comments. The SDT discussed this issue in great detail. The SDT decided that it would not be in the best interest of reliability to grant any exceptions.		
PPL NERC Registered Affiliates		N/A
Modesto Irrigation District		Need a technical justification for the various Epsilon values specified.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The Epsilon values were developed during the implementation of CPS1. These values are reviewed under the auspices of the NERC OC annually.		
PacifiCorp		PacifiCorp supports this draft.
Response: Thank you for your comments.		
PJM Interconnection, L.L.C		PJM is, in general, supportive of this standard with the exception noted in comments for question 1.
Response: Thank you for your comments. Please refer to our response to Question 1.		
Powerex Corp.		Powerex believes that the proposed draft standard is deficient in many respects as highlighted by commenters in the previous posting period. Specifically Powerex notes the following concerns in the proposed standard that highlight the inadequacy of the proposed requirements to uphold the reliability of interconnections. If these concerns are not adequately addressed the resultant standard could lead to degradation in reliability.The deficiencies include:1) The proposed standard allows for an entity to be outside of its BAAL limit for 29 minutes and be inside the limit for one minute, which provides a framework that allows an entity to possibly operate outside of the prescribed bounds 95 % of the time. The consequences of allowing such operations has not been adequately addressed by the drafting team, and allowing this standard to move forward with such latitude could lead to reliability issues. 2) The proposed standard does not restrict or limit BAs during periods of high congestion, when unscheduled flow on the entire system is causing reliability issues and/or exceedance of limits. Under the proposed standard the transmission path operators and BAs are forced to deal with unscheduled flows on the system without adequate tools or procedures in place to remedy the reliability events. During the field

Organization	Yes or No	Question 2 Comment
		trial of the proposed standard these issues have been experienced in the WECC, where congestion management of non-Qualified and Qualified paths has created various operating issues for the entities and Reliability Coordinators. The consequences of allowing unlimited use of a transmission system via unlimited unscheduled flows, without better mechanisms to control flows, could lead to reliability events. The proposed standard does not provide the authority to the Reliability Coordinators to control and/or propose new operating procedures (eg. Limiting all BAs in the interconnection to operate within L10 during period of congestion) that mitigate unscheduled flows that are adversely impacting the transmission grid. This needs to be addressed in this proposed standard so that during high congestion periods, regardless of system frequency, BAs bring ACE limits within L10 or some other suitable limitation that decreases the adverse impact.3) The proposed standard puts no limits on ACE during times of normal frequency, which allows BAs to inappropriately "lean" on other generation, or to push excessive amount of energy on to the transmission system. This deficiency allows a BA to obtain energy or push unscheduled energy across the interties during times that can be economically advantageous to the BA without regard to impacts upon neighboring BAs, load serving entities and transmission customers. It is paramount that the current standard, with CPS2, remain in place until such time that the reliability issues associated with the draft standard are resolved.

Response: Thank you for your comments.

1. **The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.**
2. **The Standard Drafting Team appreciates your concern with respect to uncertainty associated with the Field Trial Results.**

Organization	Yes or No	Question 2 Comment
However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL. 3. Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL but was not adopted by the WECC. 4. Unscheduled energy flows that do not cause reliability problems are not reliability issues. These issues should not be resolved by reliability standards that do not address reliability problems. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.		
SMUD		See comment in response #1.
Response: Thank you for your comment. Please refer to our response to Question #1.		
Tacoma Power		Tacoma Power does not support the proposed standard. BAL-001 as proposed moves forward with a control standard that has not yet been fully vetted. Since the RBC field trial began in 2010, with a significant portion of WECC BA participation, results point to noteworthy reliability and market related issues. As the RBC allows larger BAs looser control (i.e. larger ACE values) and wider frequency values, the results include: increased coordinated phase shifter operations, dramatic increase in schedule curtailments due to unscheduled flow, frequency increasing in a negative direction during heavy load hours and positive direction during light load hours, increased manual time error corrections and hours of manual time error corrections and increasing inadvertent

Organization	Yes or No	Question 2 Comment
		accumulations. All of these issues need time to be vetted by the industry and the proposed standard modified accordingly before Tacoma Power would support it.
Response: Thank you for your comments. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**		
IRC-SRC		Unless there is justification we missed, the new definitions should be removed. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
Response: Thank you for your comments. **1) SDT believes that the new definitions are needed to provide necessary clarity for the standard.** **2) The SDT has modified the definition for Reporting ACE based on the collective comments from the industry.**		

3. **If you have any other comments on BAL-001-2 that you haven't already mentioned above, please provide them here:**

Summary Consideration: The majority of the commenters provided typographical corrections to the standard and associated documents.

Some commenters stated that using a looser ACE control would result in unscheduled energy flows. The SDT explained that unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.

A few commenters felt that the SDT was trying to redefine ACE with the proposed definition of Reporting ACE. The SDT stated that the SDT was not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.

Organization	Yes or No	Question 3 Comment
Avista	No	Looser AGC control resulting from implementation of BAAL results in unscheduled flow. Increasing unscheduled flow events significantly impact each participant in the energy markets. Schedules are curtailed to accommodate RBC, thus favoring one form of generation over another. In this case, variable resources are given an advantage looser control and other parties are impacted. Although this appears to be an economic issue, any time energy schedules are curtailed for reliability reasons, reliability is negatively affected.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.**		
City of Tallahassee	No	this is not a yes/no question.
MISO Standards Collaborators	No	
ACES Standards Collaborators	No	
Oklahoma Gas & Electric	No	
Bonneville Power Administration	No	
Salt River Project	No	
PacifiCorp	No	
City of Tallahassee	No	
City of Tallahassee	No	
Manitoba Hydro	Yes	(1) Section D, Compliance, 1.1 - the paraphrased definition of 'Compliance Enforcement Authority' from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (2) Implementation Plan, Regulation Reserve Sharing Group - capitalize the words 'regulating reserve' because they appear in

Organization	Yes or No	Question 3 Comment
		the Glossary of Terms. (3) Implementation Plan, Reporting ACE - capitalize ‘net actual interchange’ and change ‘scheduled Interchange’ to ‘Net Scheduled Interchange’. (4) Implementation Plan - make same changes to definitions in Implementation Plan as suggested in Question 1 of this commenting request. (5) VRF/VSL - capitalize ‘bulk electric system’ in both the High Risk Requirement and Medium Risk Requirement sections.
Response: Thank you for your comments. **1) The SDT is using language supplied by NERC legal.** **2) The SDT has made the correction that you have identified.** **3) The SDT has made the correction that you have identified.** **4) The SDT has made the correction that you have identified.** **5) The SDT has made the correction that you have identified.**		
MRO NERC Standards Review Forum	Yes	1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. The NSRF believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. The NSRF is not asking for a change to the standard, just a clear

Organization	Yes or No	Question 3 Comment
		statement for the purposes of documenting compliance.
Response: Thank you for your comments. **1) The SDT has made the correction that you have identified.** **2) The SDT has added clarifying language to Attachment 2 to address your concern.**		
Xcel Energy	Yes	1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. Xcel Energy believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. Xcel Energy is not asking for a change to the standard, just a clear statement for the purposes of documenting compliance.
Response: Thank you for your comments. **1) The SDT has made the correction that you have identified.** **2) The SDT has added clarifying language to Attachment 2 to address your concern.**		
SPP Standards Review Group	Yes	Add an ‘s’ to ‘period’ in the 2nd line of 4.1.2 in the Applicability Section. Replace ‘greater’ with ‘more’ in the Moderate, High and Severe VSLs for R2. On Page 7 of the Background Document, in the 4th line of the 3rd

Organization	Yes or No	Question 3 Comment
		paragraph, replace 'that' with 'than' in front of CPS1.
Response: Thank you for your comments. **The SDT has made the correction in the Applicability Section that you have identified.** **The SDT does not see any difference between using the work "greater" versus "more" and therefore has decided to keep the word greater.** **The SDT has made the correction in the Background Document that you have identified.**		
Duke Energy	Yes	Duke Energy does not support the definition of Reporting ACE as written. We believe that "ACE" should be defined as "The difference between the Balancing Authority's net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error plus Automatic Time Error Correction (ATEC - If operating in the Western Interconnection and in the ATEC mode)"; followed with the equation shown and the details of the variables. "Reporting ACE" should be defined simply as the "The scan rate values of a Balancing Authority's ACE". Though Duke Energy supports the adoption of the BAAL; it's not clear why all of the other changes to the standard are needed, nor is it clear how these changes respond to FERC directives. We believe that it should be mentioned that the BAAL addresses the FERC directive to develop a standard addressing the large loss of load - the BAAL measure will ensure appropriate response to any event causing the Balancing Authority's ACE to exceed its BAAL (see comments to BAL-013 for further details). Duke Energy agrees with the proposed change to the BAAL equation to accommodate Time-Error Corrections by placing Scheduled Frequency in the numerator and denominator in place of 60 Hz;

Organization	Yes or No	Question 3 Comment
		however it is not clear why Balancing Authorities under the Field Trial have not yet been afforded the opportunity to incorporate the same change in the BAAL calculation in their tools. Duke Energy would support allowing the Balancing Authorities under the Field Trial to make the appropriate changes in their tools to be consistent with the BAAL equation as proposed, and would support the drafting team updating the tools on the NERC Field Trial website to be consistent with the current BAL-001-2 posted.
Response: Thank you for your comments. **The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.** **The SDT agrees with your comment concerning the field trial. The SDT will look into the concern you have identified.**		
Exelon	Yes	Exelon is basically fine with structure.
Response: Thank you for your comment.		
Idaho Power Company	Yes	I believe that operating under the BAAL does not pose a threat to reliability and could help mitigate variable resource integration provided that BAs do not stress the limits during normal operations. If BAs could be encouraged to follow expected changes in system demand reasonably close during normal conditions then the system could more readily absorb unexpected events. However, I'm not sure how this can be addressed within a standard.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments.		
Keen Resources Ltd.	Yes	The Frequency Trigger Limit is set too tight at 3 standard deviations. This causes too many initial exceedences of BAAL as revealed in the field tests. This prompts BAs to wait until enough of them disappear by themselves to make it feasible to address all of the remainder. But, by waiting, the BA is failing to address the remainder early enough before they become outright violations. Instead, it would be better for reliability to raise the Frequency Trigger Limit to, say, 4 or 5 standard deviations to reduce the number of initial exceedences of BAAL to the point where it is feasible to address ALL of them immediately. What reliability is gained by a tighter limit that is feasible only if the BAs wait to address any and all of the exceedences? Furthermore, no legitimate statistical justification was ever provided for the tight 3-standard-deviations Frequency Trigger Limit. The very flawed attempt to provide such a justification led to rejection of the first version of this standard put out for balloting. No further formal technical justification was thereafter developed on which to base that or a wider limit, despite acknowledgement for a time on the drafting team that it was needed.
Response: Thank you for your comments. **The drafting team has considered other alternative approaches and has selected the 3 epsilon model as the best and fairest model for the requirement. BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability.**		
seattle city light	Yes	The Guidelines document purported to address issues such as those discussed in question 2 above will not be available for review until summer 2013. Lacking such a document, Seattle City

Organization	Yes or No	Question 3 Comment
		Light cannot support this draft of BAL-001-2.
Response: Thank you for your comments. **The Guidelines Document is anticipated to be posted by July 19, 2013.**		
NextEra Energy	Yes	The High Frequency Limit (FTLhigh) calculated as Fs + 3Ô1i should be changed to Fs + 4Ô1i
Response: Thank you for your comments. **The SDT believes that the High Frequency Limit is calculated properly as currently written in the standard. Without further information as to why you believe it is incorrect, the SDT cannot address your issue.**		
Tucson Electric Power Co	Yes	Using the newly-defined term Reporting (ATEC) ACE is a positive change. Using Scheduled Frequency instead of 60Hz in the BAAL calculation is also a positive change.
Response: Thank you for your comments.		
American Electric Power	Yes	We would encourage the drafting team to provide Generator Operators with the appropriate requirements to support the Balancing Authorities. As currently drafted, the Balancing Authority may be the sole entity responsible for meet the obligations of the standard, and yet it does not have direct control over the Generator Operator to ensure the BA receives what is needed. At the least, the BA might need some sort of recourse specified in the event a Generator Operator is not acting in a cooperative manner (for example, a Generator Operator who refuses to adhere to their agreed-upon schedule in real time, but is not penalized because they integrate over the hour).

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **The SDT understands your concern but believes that it is outside the scope of this project. The SDT believes that this is a commercial issue that should be addressed by FERC.**		
EnerVision, Inc.	Yes	
Energy Mark, Inc.	Yes	
SERC OC Standards Review Group		: We do not believe it is appropriate to include a region or interconnection specific definition in a continent-wide standard. However, we would not object to including a generic term for time-control adjustment.These comments were also supported by Ron Carlsen with Southern Company.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you for your comments. **The SDT is only attempting to recognize the approved variance that was granted to the WECC.**		
PPL NERC Registered Affiliates		LGE and KU Services is a participant in the BAAL Field Test and support the implementation of the BAAL standard
Response: Thank you for your comments.		
Portland General Electric Company		PGE is generally supportive of the underlying goal of this standard revision - increased coordination between BAs for efficiently and reliably, meeting Control Performance Standards through the development of a Regulation Reserve Sharing Group, or other yet

Organization	Yes or No	Question 3 Comment
		to be named program. However, PGE is concerned the proposed standard does not adequately address the reliability concerns associated with unscheduled flow and degraded frequency response metrics that have been witnessed with the current WECC Reliability Based Control pilot program. PGE believes the unique physical transmission properties of the Western Interconnect dictate a need for increased consideration of reliability protections for our region prior to the adoption of new nation-wide standards.
Response: Thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.**		
Powerex Corp.		Powerex believes that the reliability issues with the current draft standard have not been adequately addressed by the drafting team. The reliability issues that have been previously submitted by commenters raised valid concerns, and the drafting team has not addressed those specific concerns in their responses. Powerex submits the following subsequent comments: 1) In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for inadvertent energy flows between adjacent BAs to both jeopardize reliability and to cause undue harm to customers on the grid. Such inadvertent energy flows are driven by the size of each BAAs ACE, but are primarily contained by CPS2 under the current BAL-001. FERC also made it clear that it was inappropriate for generators

Organization	Yes or No	Question 3 Comment
		within a BAA to “dump power on the system or lean on other generation...The tiered imbalance penalties adopted in the Final Rule generally provide a sufficient incentive not to engage is such behavior”The proposed standard will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impacts and which could lead to exceedances in SOL due to large ACEs. The proposed performance standard does not address the potential for a single BA to lean on the grid with deliberate unscheduled energy flows or inadvertent energy, taking any accumulated benefits for itself and harming other entities on the grid. The detrimental impacts of deliberate inadvertent flows to load customers and transmission customers on the grid could be substantial when large ACE deviations cause transmission limit exceedances. It is imperative that the drafting team address this issue in the standard. 2) Various entities have also expressed concerns regarding the reliability impacts of inadvertent or unscheduled flows. The issues experienced by entities during the Field Trial were provided in the previous comment period, but the drafting team has failed to address the comments adequately. Furthermore, the drafting team ignored the concerns and provided a generic response to commenters from NE ISO, WECC, Tucson, APS, BPA and NPPD. These concerns regarding the BAAL standard include comments such as:a. Reliability concerns over BAAL limits not accounting for large ACE excursions b. Increase in transmission limit exceedances c. Interconnection exposed due to the lack of ACE bounding d. CPS 2 is a more reliable metrice. Allows for more unscheduled power flows and amount of unscheduled interchange a BA can have is not cappedf. WECC average frequency deviation has been increasingg. Elimination of CPS2 has a detrimental impact on

Organization	Yes or No	Question 3 Comment
		reliability h. Leads to transmission constraints and requires TOPs and RCs to restrict the unscheduled flows on the system due to a BA unilaterally over or under generatingi. WECC has experienced many SOL violations due to Large ACEs 3) After reviewing the previous comments and responses, it has become abundantly clear that the drafting team chose to respond to commenters with generic statement such as “The drafting team conducts a monthly call to review the results from the BAAL field trial. There have not been any reliability issues raised by any RC during these calls. The drafting team encourages BA’s and RC’s to share any specific occurrences that they feel have reliability impacts as a result of operating under BAAL.”, but did not specifically address, revise or enhance the proposed standard based on the comments.These generic statements are not appropriate by a drafting team and could be considered as dismissive.. The drafting team seems to be suggesting that the “monthly call” mentioned in the drafting team’s response is the only forum where reliability concerns need to be addressed. As an example, WECC submitted comments and provided information on RC actions and asked for the drafting team to remedy the issue in the standard, and I quote “During Phase 3, the Reliability Coordinators (RC) reported several SOL exceedance associated with high ACE. The SOL exceedances were mitigated when RCs requested the high ACE value to be reduced to L10.The SDT must address transmission loading issues caused by high ACE.”The drafting team did not adequately address this issue, which was raised by a regional entity, and responded by issue a generic statement that since this issue wasn’t discussed on the monthly phone call that these issues or experiences in WECC are not true reliability issues. It is imperative that the drafting team revisit all

Organization	Yes or No	Question 3 Comment
		those comments that have been received and make appropriate revisions, and additions to the standard address the reliability concerns raised by the entities regarding SOL exceedance, transmission loading, and unscheduled flow issues. 4) Powerex believes that the current field trial has not proven to be more reliable, and it is imperative that the issues surrounding the increases in frequency error, exceedance of SOL and transmission limits be addressed. There has been no comparison or evidence provided that shows that the proposed standard is superior in reliability than CPS2. Several commenters have raised concerns with the elimination of CPS2, and impacts associated with the increase of frequency error and unscheduled interchange due to large ACE deviations, which pose a greater risk to reliability than the current CPS2 requirement. The drafting team cannot provide a generic statement that “BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability” without providing any evidence or data to test the validity of those statements. The drafting team has not provided any supporting evidence or data that would validate such a generic statement, nor has it provided any benefits that were realized during the field trial and resulted in enhanced reliability. On the contrary, WECC has experienced a degradation of reliability measures, impacts to commercial transmission customers, as well as reliability issues that required RC intervention during the field trial. Those detrimental effects of the proposed standard cannot be offset by the drafting team providing generic and unsupported statements. 5) Powerex believes that the standard should have a BAALHigh and BAALLow in place at all time in order to manage ACE

Organization	Yes or No	Question 3 Comment
		deviations that may jeopardize reliability through unscheduled flows, which can lead to exceedance of SOL and transmission limits. For example, WECC membership found it appropriate to apply a limit of 4 times a BA's L10. This mechanism provides flexibility to handle interconnection frequency while not allowing ACE deviations to become so significant that BA flows negatively impact the transmission system. 6) The drafting team stated in their response to previous comments that "The drafting team will be preparing a report based on the field trial results that will be posted prior to the FERC filing for this draft standard". Powerex poses two questions to the drafting team: a) Why have the field trial results not been provided to NERC membership prior to ballot body? b) Why have the results for the field trial not been updated on the project page on the NERC website since June 2012? 7) The drafting team has not adequately addressed the issue of "sawtoothing" operations as exhibited by entities during the field trial. Sawtoothing can be described as entities that are allowing ACE to be unlimited for 29 minutes and then be brought under BAAL limits for 1 minute. This type of behavior is shown in the NERC reports posted on the field trial. The drafting team is hedging that entities will not operate in this manner after the field trial due to higher operation and compliance risk to entities. However, the NERC field trial should have created disincentives to not allow such behavior during the onset of the field trial, and requirements should have been adopted to discourage behavior that poses reliability risks.

Organization	Yes or No	Question 3 Comment
Response: The SDT thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.** **The BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit.** **With the change in SDT leadership, some of the field trial data was not getting posted. The data is now posted and the SDT leadership is attempting to post the information on a monthly basis.**		
Tacoma Power		Tacoma Power does not support a standard that institutionalizes a control methodology that is still in the development stage and is not supported by actual data. Thank you for consideration of our comments.
Response: Thank you for your comments. **The SDT does not agree that the requirements in BAL-001-2 are a control methodology.**		
Texas Reliability Entity		The latest changes to the VSLs for R2 made them more confusing. We would suggest re-wording them to state, for example: "The Balancing Authority exceeded its clockâ€�minute BAAL for more than 30 consecutive clock minutes and for less than or equal to 45 consecutive clock minutes."
Response: Thank you for your comments. **The SDT believes that the wording presently used in the VSLs provides the necessary clarity. In addition, your concern that the VSLs are confusing has not been supported by the rest of the industry.**		

END OF REPORT

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Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

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

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the Frequency Bias Setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$I_{ATEC} = \frac{\mathrm{PII}_{\text{accum}}^{\text{on/off peak}}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

$\boldsymbol{I_{ATEC}}$ shall be zero when operating in any other AGC mode.

- $Y = B / B_S$.
- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$\mathrm{PII}_{\text{accum}}^{\text{on/off peak}} = \text{last period's } \mathrm{PII}_{\text{accum}}^{\text{on/off peak}} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the

Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.
3. The use of a common Scheduled Frequency F_S for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** **BAL-001-2**
3. **Purpose:** To control Interconnection frequency within defined limits.
4. **Applicability:**

   4.1. Balancing Authority

   4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

   4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

   4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

   5.1. 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 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, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting 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 Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

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

And,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where**:**

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)

$BAAL_{High}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_S - $3\varepsilon 1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as F_S + $3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

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To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period

data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

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NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those T~~t~~ie L~~l~~ines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

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- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\ peak} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an I~~i~~nterconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the I~~i~~nterconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area N~~n~~et I~~i~~nterchange S~~s~~chedules and all N~~n~~et I~~i~~nterchange actual values is equal to zero at all times.
3. The use of a common S~~s~~cheduled F~~f~~requency F_S for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the I_{ME} term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**

2. **Number:** **BAL-001-2**

3. **Purpose:** To control Interconnection frequency within defined limits.

4. **Applicability:**

   4.1. Balancing Authority

   4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

   4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

   4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

   5.1. First day of the first calendar quarter that is twelve~~six~~ 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 the first day of the first calendar quarter that is twelve~~six~~ months beyond the date this standard is approved by the NERC Board of Trustees~~'~~, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar ~~-~~month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, ~~as~~ calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, ~~Energy Management s~~System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, ~~Energy Management s~~System logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the C~~c~~ompliance E~~e~~nforcement A~~a~~uthority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its C~~c~~ompliance E~~e~~nforcement A~~a~~uthority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The C~~c~~ompliance E~~e~~nforcement A~~a~~uthority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding ~~on a rolling~~ 12 consecutive calendar~~-~~ month period~~basis~~, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding~~on a rolling~~ 12 consecutive calendar~~-~~ month period~~basis~~, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding ~~on a rolling~~ 12 consecutive calendar~~-~~ month period~~basis~~, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding ~~on a rolling~~ 12 consecutive calendar~~-~~ month period~~basis~~, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

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

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding ~~consecutive~~ 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding ~~consecutive~~ 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting 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 Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

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

And,

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

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

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

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

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

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

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

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

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

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

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where**:**

$\mathbf{BAAL_{Low}}$ is the Low Balancing Authority ACE Limit (MW)

$\mathbf{BAAL_{High}}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as $F_S - 3\varepsilon 1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as $F_S + 3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period

data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-2 – Real Power Balancing Control Performance

Approvals Required
BAL-001-2 – Real Power Balancing Control Performance

Prerequisite Approvals
None

Revisions to Glossary Terms
The following definitions shall become effective when BAL-001-2 becomes effective:

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Rreserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement.

Reporting ACE: The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

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

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A (Actual Net Interchange) is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.

10 is the constant factor that converts the frequency bias setting units to MW/Hz.

F_A (Actual Frequency) is the measured frequency in Hz.

F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.

I_{ME} (Interchange Meter Error) is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

I_{ATEC} (Automatic Time Error Correction) is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$I_{ATEC} = \dfrac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

- Y = B / B_S.
- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.

- ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

  $\Delta TE = TE_{end\ hour} – TE_{begin\ hour} – TD_{adj} – (t)*(TE_{offset})$

- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.
- t is the number of minutes of Manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required.

  Where:

$$PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\,peak} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.
2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.
3. The use of a common Scheduled Frequency FS for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)

Interconnection: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

The existing definition of Interconnection should be retired at midnight of the day immediately prior to the effective date of BAL-001-2, in the jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Regulation Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-2 shall become effective as follows:

> 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 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, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The twelve-month period for implementation of BAL-001-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-2a — Reliability Coordination — Current Day Operations

IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

Implementation Plan

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

Implementation Plan for BAL-001-2 – Real Power Balancing Control Performance

Approvals Required

BAL-001-2 – Real Power Balancing Control Performance

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-001-2 becomes effective:

Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the R~~r~~egulating R~~r~~eserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

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- H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.
- B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B * \Delta TE/6)$
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  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$

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  Where:

$$PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\ peak} + \mathbf{PII_{hourly}}$$

All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an ~~i~~Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.

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3. The use of a common S~~s~~cheduled F~~f~~requency FS for all areas at all times.
4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)

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The proposed revised definition for "Interconnection" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document.

Applicable Entities

Balancing Authority

Regulation Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-001-2 shall become effective as follows:

> First day of the first calendar quarter that is twelve~~six~~ 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 the first day of the first calendar quarter that is twelve~~six~~ months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The twelve~~six~~-month period for implementation of BAL-001-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to perform the BAAL calculations for compliance.

Retirements

BAL-001-0.1a – Real Power Balancing Control Performance should be retired at midnight of the day immediately prior to the effective date of BAL-001-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Interconnection"

BAL-001-0.1a — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-002-1 — Disturbance Control Performance
BAL-003-0.1b — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-004-1 — Time Error Correction
BAL-004-WECC-01 — Automatic Time Error Correction
BAL-005-0.1b — Automatic Generation Control
BAL-006-2 — Inadvertent Interchange
WECC Standard BAL-STD-002-1 - Operating Reserves
CIP-001-1a — Sabotage Reporting
CIP-001-2a— Sabotage Reporting
CIP–002–4 — Cyber Security — Critic a l Cyber Asset Identification
CIP–005–3a — Cyber Security — Electronic Security Perimeter(s)
COM-001-1.1 — Telecommunications
EOP-001-2b — Emergency Operations Planning
EOP-002-2.1 — Capacity and Energy Emergencies
EOP-002-3 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-003-2— Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-005-2 — System Restoration from Blacks tart Resources
EOP-006-1 — Reliability Coordination — System Restoration
EOP-006-2 — System Restoration Coordination
FAC-008-3 — Facility Ratings
FAC-010-2 — System Operating Limits Methodology for the Planning Horizon
FAC-011-2 — System Operating Limits Methodology for the Operations Horizon
INT-005-3 — Interchange Authority Distributes Arranged Interchange
INT-006-3 — Response to Interchange Authority
INT-008-3 — Interchange Authority Distributes Status
IRO-001-1.1 — Reliability Coordination — Responsibilities and Authorities
IRO-001-2 — Re liability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-002-2 — Reliability Coordination — Facilities
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-2a — Reliability Coordination — Current Day Operations

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IRO-005-3a — Reliability Coordination — Current Day Operations
IRO-006-5 — Reliability Coordination — Transmission Loading Relief
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-014-2 — Coordination Among Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0 — Development of Interconnection-Specific Steady State System Models
MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
MOD-015-0.1 — Development of Interconnection-Specific Dynamics System Models
MOD-030-02 — Flowgate Methodology
PRC-001-1 — System Protection Coordination
PRC-006-1 — Automatic Underfrequency Load Shedding
TOP-002-2a — Normal Operations Planning
TOP-004-2 — Transmission Operations
TOP-005-1.1a — Operational Reliability Information
TOP-005-2a — Operational Reliability Information
TOP-008-1 — Response to Transmission Limit Violations
VAR-001-1 — Voltage and Reactive Control
VAR-001-2 — Voltage and Reactive Control
VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

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BAL-001-2 – Real Power Balancing Control Performance Standard Background Document

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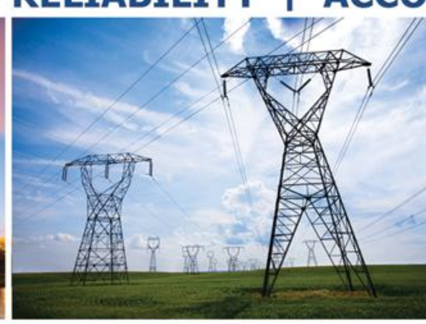


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Introduction

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The original work for this standard was done by the Balancing Authority Controls standard drafting team, which later joined with the Reliability-based Control Standard drafting team. These combined teams were renamed Balance Authority Reliability-based Control standard drafting team (BARC SDT).

The purpose of proposed Standard BAL-001-2 is to maintain Interconnection frequency within predefined frequency limits. This draft standard defines Balancing Authority ACE Limit (BAAL), and required the Balancing Authority (BA) to balance its resources and demand in Real-time so that its clock-minute average of its Area Control Error (ACE) does not exceed its BAAL for more than 30 consecutive clock-minutes.

As a proof of concept for the proposed BAAL standard, a BAAL field trial was approved by the NERC Standards Committee and the Operating Committee. Currently participating in the field trial are 13 Balancing Authorities in the Eastern Interconnection, 26 Balancing Authorities in the Western Interconnection, the ERCOT Balancing Authority, and Quebec. Reliability Coordinators for all Interconnections continue to monitor the performance of those participating Balancing Authorities and provide information to support monthly analysis of the BAAL field trial. As of the end of September 2011, no reliability issues with the BAAL field trial have been identified by any Reliability Coordinator. The Western Interconnection has experienced changes during the field trial with potential degradation to transmission; however, no explicit linkage has been determined between the field trial and these degradations. For further information on the results of the Western Interconnection, please refer to the WECC Reliability-based Control Field Trial Report.

Historical Significance

A1-A2 Control Performance Policy was implemented in 1973 as:

- A1 required the Balancing Authority's ACE to return to zero within 10 minutes of previous zero.
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  - Lack of theoretical justification
  - Large ACE treated the same as a small ACE, regardless of direction
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In 1996, a new NERC policy was approved which used CPS1, CPS2, and DCS.

CPS1is a:

- Statistical measure of ACE variability
- Measure of ACE in combination with the Interconnection's frequency error
- Based on an equation derived from frequency-based statistical theory

CPS2 is:

- Designed to limit a Control Area's (now known as a Balancing Authority) unscheduled power flows
- Similar to the old A2 criteria

The proposed BAL-001-2 retains CPS1, but proposes a new measure BAAL to replace CPS2. Currently CPS2:

- Does not have a frequency component.
- CPS2 many times give the Balancing Authority the indication to move their ACE opposite to what will help frequency.
- Only requires Balancing Authorities to comply 90 percent of the time as a minimum.

Background and Rationale by Requirement

Requirement 1

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly.

Background and Rationale

Requirement R1 is not a new requirement. It is a restatement of the current BAL-001-0.1a Requirement R1 with its equation and explanation of its individual components moved to an attachment, Attachment 1 - Equations Supporting Requirement R1 and Measure M1. This requirement is commonly referred to as Control Performance Standard 1 (CPS1). R1 is intended to measure how well a Balancing Authority is able to control its generation and load management programs, as measured by its Area Control Error (ACE), to support its Interconnection's frequency over a rolling one-year period.

CPS1 is a measure of a Balancing Authority's control performance as it relates to its generation, Load management, and Interconnection frequency when measured in one-minute averages over a rolling one-year period. If all Balancing Authorities on an Interconnection are compliant with the CPS1 measure, then the Interconnection will have a root mean square (RMS) frequency error less than the Interconnection's Epsilon 1.

A Balancing Authority reports its CPS1 value to its regional entity each month. This monthly value provides trending data to the Balancing Authority, NERC resources subcommittee, and others as needed to detect changes that may indicate poor control on behalf of the Balancing Authority. Requirement R1 remains unchanged, although the wording of the requirement was modified to provide clarity

Additionally, the drafting team added Regulating Reserve Sharing Group as a Responsible Entity, allowing Balancing Authorities to form Regulating Reserve Sharing Groups. This allows the Regulating Reserve Sharing Group to meet compliance as a group for CPS1. The drafting team also added the defined term Reserve Sharing Reporting ACE to facilitate Regulating Reserve Sharing Groups demonstration of compliance. This facilitates the consolidation of Balancing Authorities Areas for BAL-001 through contractual arrangements forming a virtual Balancing Authority Area while allowing each individual entity to maintain their political boundaries.

Requirement 2

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

Background and Rationale

Requirement R2 is a new requirement intended to replace existing BAL-001-0.1a Requirement R2, commonly referred to as Control Performance Standard 2 (CPS2). The proposed Requirement R2 is intended to enhance the reliability of each Interconnection by maintaining frequency within predefined limits under all conditions.

The Balancing Authority ACE Limits (BAAL) are unique for each Balancing Authority and provide dynamic limits for its Area Control Error (ACE) value limit as a function of its Interconnection frequency. BAAL was derived based on reliability studies and analysis which defined a Frequency Trigger Limit (FTL) bound measured in Hz. The FTL is equal to Scheduled Frequency, plus or minus three times an Interconnection's Epsilon 1 value. Epsilon 1 is the root mean square (RMS) targeted frequency error for each Interconnection, as recommended by the NERC Resources Subcommittee and approved by the NERC Operating Committee. Epsilon 1 values for each Interconnection are unique. When a Balancing Authority exceeds its BAAL, it is providing more than its share of risk that the Interconnection will exceed its FTL. When all Balancing Authorities are within their BAAL (high and low), the Interconnection frequency will be within its FTL limits.

BAAL is defined by two equations; BAAL low and BAAL high. BAAL low is for Interconnection frequency values less than Scheduled Frequency, and BAAL high is for Interconnection frequency values greater than Scheduled Frequency. BAAL values for each Balancing Authority

are dynamic and change as Interconnection frequency changes. For example, as Interconnection frequency moves from Scheduled Frequency, the ACE limit for each Balancing Authority becomes more restrictive. The BAAL provides each Balancing Authority a dynamic ACE limit that is a function of Interconnection frequency.

CPS2 was not designed to address Interconnection frequency. Currently, it measures the ability of a Balancing Authority to maintain its average ACE within a fixed limit of plus or minus a MW value called L_{10}. To be compliant, a Balancing Authority must demonstrate its average ACE value during a consecutive 10-minute period was within the L_{10} bound 90 percent of all 10-minute periods over a one-month period. While this standard does require the Balancing Authority to correct its ACE to not exceed specific bounds, it fails to recognize Interconnection frequency. For example, the Balancing Authority may be increasing or decreasing generation to meet its CPS2 bounds, even if this is a direction that reduces reliability by moving Interconnection frequency farther from its scheduled value. CPS2 allows a Balancing Authority to be outside its ACE bounds 10 percent of the time. There are 72 hours per month that a Balancing Authority’s ACE can be outside its L_{10} limits and be compliant with CPS2.

In summary, the proposed BAAL requirement will provide dynamic limits that are Balancing Authority and Interconnection specific. These ACE values are based on identified Interconnection frequency limits to ensure the Interconnection returns to a reliable state when an individual Balancing Authority’s ACE or Interconnection frequency deviates into a region that contributes too much risk to the Interconnection. This requirement replaces and improves upon CPS2, which is not dynamic, is not based on Interconnection frequency, and allows for a Balancing Authority’s ACE value to be unbounded for a specific amount of time during a calendar month.

Change From 60Hz to Scheduled Frequency

The base frequency for the determination of BAAL was changed from 60 Hz to Scheduled Frequency, $\mathbf{F_S}$. This change was made to resolve a long-standing problem with the requirement as first presented by the Balancing Resources and Demand Standard Drafting Team. The following presents information about the reason for the initial choice of 60 Hz and the need to change this value to Scheduled Frequency.

The initial BAAL equations were developed upon the assumption that the Frequency Trigger Limit (FTL) should be based upon Scheduled Frequency as shown in this draft of the standard. During initial development of values for the FTL the BRD SDT used a deterministic method for the selection of FTL based upon the Under-Frequency Relay Limit (UFRL) of an interconnection. Since the Under-Frequency Relay Limit of the interconnection is fixed the SDT chose to use a fixed value of starting frequency that would maintain a fixed frequency difference between the FTL and the UFRL. Therefore, the BRD SDT chose to base BAAL on a starting frequency of 60 Hz

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Shortly after the field trial started, directed research supporting the selection of the FTL for the Eastern Interconnection was completed. Unfortunately, the methods used to support the selection of an FTL for the Eastern Interconnection could not be repeated successfully for the other interconnections. Included in the final report was a recommendation that a multiple of 3 to 4 times the ε_1 for the interconnection could provide an acceptable alternative choice for determining the FTL.[1] Since the field trial had already started, no change was made to the initial FTL for the Eastern Interconnection, but as additional interconnections joined the field trial the FTL for these new interconnections was based on 3 times ε_1 for the interconnection. This change broke the linkage between FTL and the UFRL and eliminated the justification for using 60 Hz as the only acceptable starting frequency.

As data accumulated from the Eastern Interconnection field trial, it became apparent that Time Error Correction (TEC) causes a detrimental reliability impact. The BAC SDT recognized this problem and initiated actions to provide a case to eliminate TEC based on its effect on reliability. This activity caused the RBC SDT and later the BARC SDT to defer any action on the substitution of Schedule Frequency for 60 Hz in the BAAL Equations until the TEC issue was resolved because the elimination of TEC would eliminate the need for change. When the ERO decided to continue to perform TEC, that decision relieved the BARC SDT of responsibility for the reliability impact of TEC and required the team to instead consider the impact that BAAL could have on the effectiveness of the TEC process and any conflicts that would occur with other standards.

Two conflicts have been identified between BAAL and other standards. The first is a conflict between the BAAL limit and Scheduled Frequency when an interconnection is attempting to perform TEC by adjusting the Scheduled Frequency to either 59.98 of 60.02 Hz. The second is a conflict that results in BAAL providing an ACE limit that is more restrictive than CPS1 when an interconnection is performing TEC. These problems can both be resolved by basing the BAAL Limit on Scheduled Frequency instead of 60 Hz. Eight graphs follow that show the conflict between BAAL as currently defined using 60 Hz and other standards and how the change from 60 Hz to Scheduled Frequency resolves the conflict.

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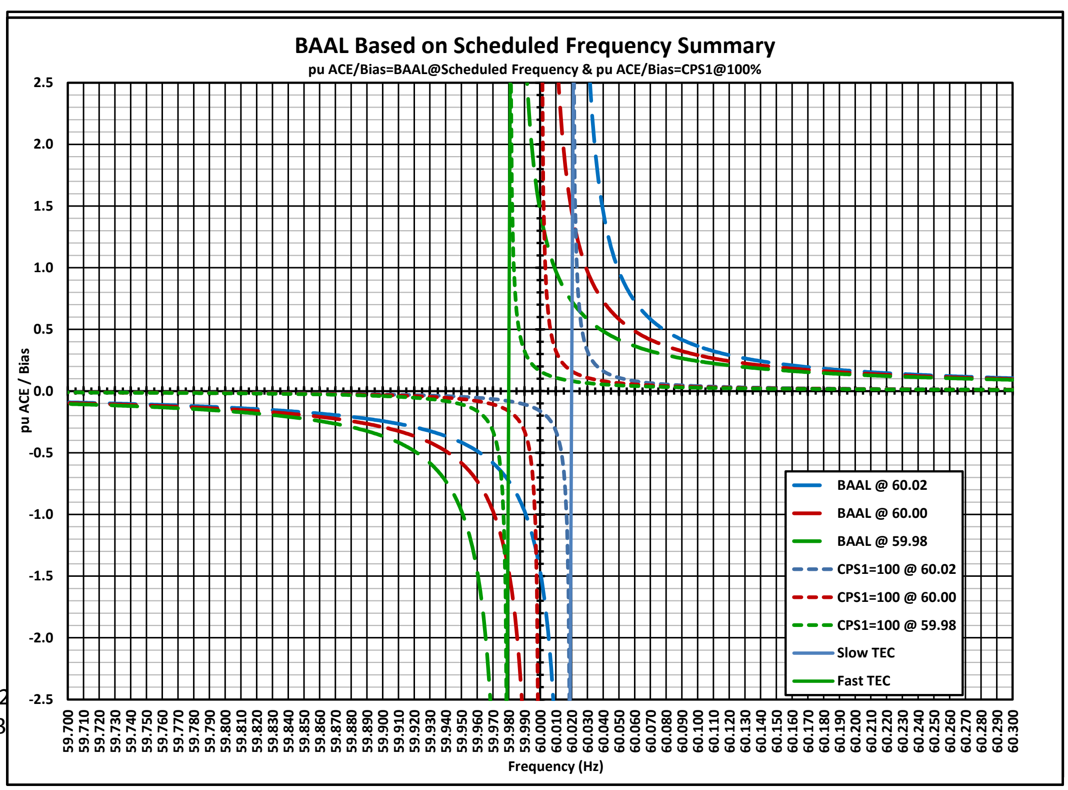

Figure 8. BAAL Based on Scheduled Frequency Summary

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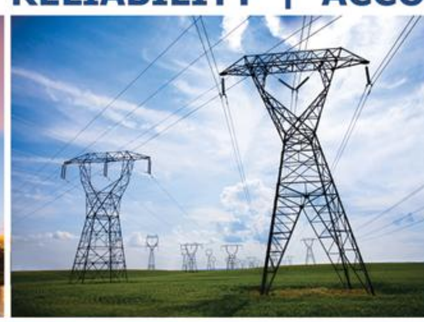


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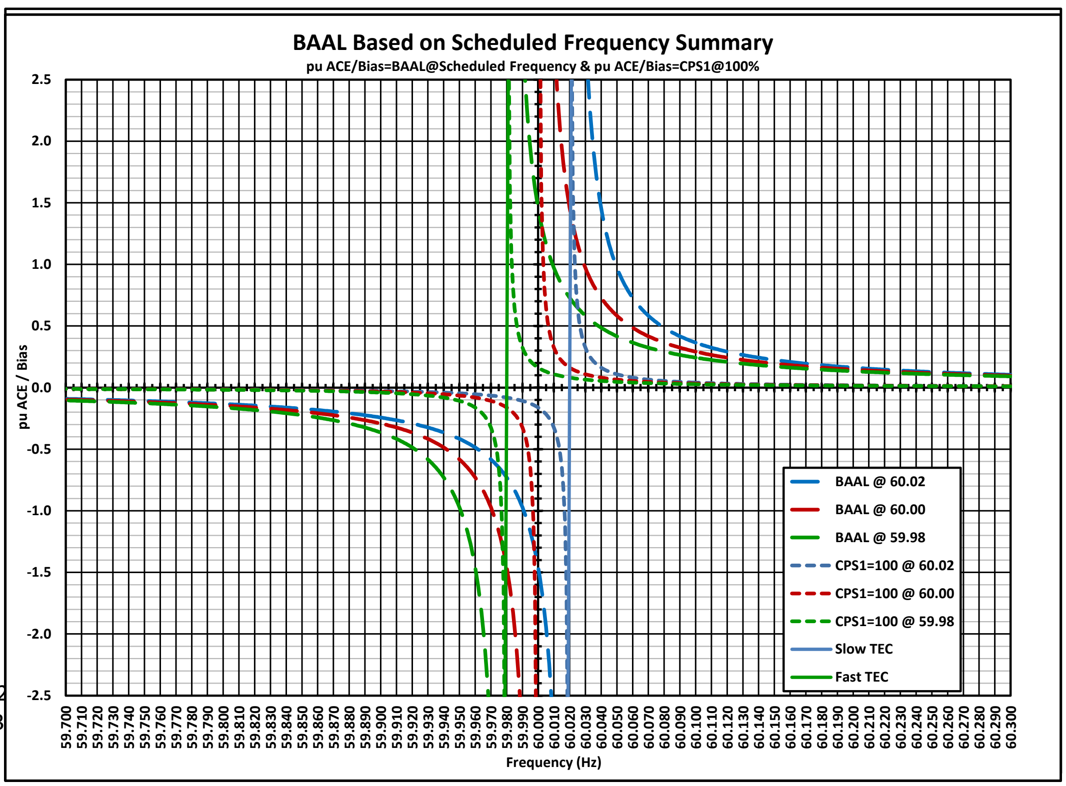

Figure 8. BAAL Based on Scheduled Frequency Summary

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-001-2, Real Power Balancing Control Performance. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature, and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-001-2:
There are two requirements in BAL-001-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-001-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a Standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-001-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-001-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation-per-day basis is the "default" for penalty calculations.

VSLs for BAL-001-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated CPS1.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of intervals the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-001-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated BAAL.	This is a new requirement. As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-001-2, Real Power Balancing Control Performance. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to B~~b~~ulk E~~e~~lectric S~~s~~ystem instability, separation, or a cascading sequence of failures, or could place the B~~b~~ulk E~~e~~lectric S~~s~~ystem at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the B~~b~~ulk E~~e~~lectric S~~s~~ystem, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature, and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-001-2:
There are two requirements in BAL-001-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-001-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a Standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-001-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-001-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-001-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation-per-day basis is the "default" for penalty calculations.

VSLs for BAL-001-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated CPS1.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of intervals the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-001-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated BAAL.	This is a new requirement. As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the percentage of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider results of the calculation required. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-001-2 Real Power Balancing Control Performance Mapping Document

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each	This Requirement has been moved into BAL-001-2 Requirement R1	Requirement R1 The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. The calculation equation for CPS1 has been moved to Attachment 1 of BAL-001-2.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. AVG_{Period} ______ $-10B$ The equation for ACE is: $ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ where: • NI_A is the algebraic sum of actual flows on all tie lines. • NI_S is the algebraic sum of scheduled flows on all tie lines. • B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz. • F_A is the actual frequency. • F_S is the scheduled frequency. F_S is normally 60		

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Hz but may be offset to effect manual time error corrections. • I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.		
R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. $AVG\text{10-minute}(ACE_i) \le L_{10}$ where:	This Requirement has been removed from BAL-001-2 and replaced with the proposed Requirement R2 for BAAL.	Requirement R2 Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
L_{10}=1.65 ϵ_{10} ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.		The calculation equation for BAAL is located in Attachment 2 of BAL-001-2.
R3. Each Balancing Authority providing Overlap Regulation Service shall	This Requirement has been moved into the BAL-001-2	Attachment 1 A Balancing Authority providing Overlap Regulation Service

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
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.	Attachment 1.	to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving Regulation Service.
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).	This Requirement has been moved into the BAL-001-2 Applicability Section.	Applicability Section 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

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Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-001-2 Real Power Balancing Control Performance Mapping Document

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each	This Requirement has been moved into BAL-001-2 Requirement R1	Requirement R1 The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100% for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. The calculation equation for CPS1 has been moved to Attachment 1 of BAL-001-2.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. AVG_{Period} ______ $-10B$ The equation for ACE is: $ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ where: • NI_A is the algebraic sum of actual flows on all tie lines. • NI_S is the algebraic sum of scheduled flows on all tie lines. • B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz. • F_A is the actual frequency. • F_S is the scheduled frequency. F_S is normally 60		

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
Hz but may be offset to effect manual time error corrections. • I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.		
R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. AVG10-minute $(ACE_i) \leq L_{10}$ where:	This Requirement has been removed from BAL-001-2 and replaced with the proposed Requirement R2 for BAAL.	Requirement R2 Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, ~~as~~ calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
L_{10}=1.65 ϵ_{10} ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.		The calculation equation for BAAL is located in Attachment 2 of BAL-001-2.
R3. Each Balancing Authority providing Overlap Regulation Service shall	This Requirement has been moved into the BAL-001-2	Attachment 1 A Balancing Authority providing Overlap Regulation Service

BAL-001-0.1a Mapping to Proposed NERC Reliability Standard BAL-001-2		
Standard BAL-001-0.1a NERC Board Approved	**Comment**	**Proposed Standard BAL-001-2**
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.	Attachment 1.	to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving Regulation Service.
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).	This Requirement has been moved into the BAL-001-2 Applicability Section.	Applicability Section 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-001-2

Final Ballot is now open through Thursday, July 25, 2013

Now Available

A final ballot for **BAL-001-2- Real Power Balancing Control Performance** is now open **through 8 p.m. Eastern on Thursday, July 25, 2013.**

The other standard (BAL-002-2) in this project will be posted and announced separately at a later date.

Background information for this project can be found on the project page.

Instructions

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for **BAL-001-2** will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-001-2

Final Ballot Results

Now Available

A final ballot for **BAL-001-2- Real Power Balancing Control Performance** concluded at **8 p.m. Eastern on Thursday, July 25, 2013.**

Voting statistics for the final ballot are listed below, and the Ballot Results page provides a link to the detailed results.

Approval
Quorum: 92.31% Approval: 74.54%

Background information for this project can be found on the project page

Next Steps
The standard will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-001-2 Final Ballot
Ballot Period:	7/16/2013 - 7/25/2013
Ballot Type:	Final Ballot
Total # Votes:	324
Total Ballot Pool:	351
Quorum:	**92.31 % The Quorum has been reached**
Weighted Segment Vote:	74.54 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	53	0.736	19	0.264	7	11
2 - Segment 2.	10	0.9	5	0.5	4	0.4	1	0
3 - Segment 3.	79	1	48	0.727	18	0.273	7	6
4 - Segment 4.	24	1	15	0.75	5	0.25	0	4
5 - Segment 5.	75	1	47	0.758	15	0.242	9	4
6 - Segment 6.	54	1	34	0.694	15	0.306	3	2
7 - Segment 7.	2	0.2	2	0.2	0	0	0	0
8 - Segment 8.	6	0.5	5	0.5	0	0	1	0
9 - Segment 9.	3	0.3	1	0.1	2	0.2	0	0
10 - Segment 10.	8	0.7	7	0.7	0	0	1	0
Totals	**351**	**7.6**	**217**	**5.665**	**78**	**1.935**	**29**	**27**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	

1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Abstain	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Lloyd A Linke	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Abstain	
3	Lincoln Electric System	Jason Fortik	Affirmative	

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	National Grid USA	Brian E Shanahan	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Self	Herb Schrayshuen	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	

5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Colorado Springs Utilities	Michael Shultz	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Abstain	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Leo Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	

5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto	Abstain	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Negative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis	Negative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew	Affirmative	

8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		Robert Blohm	Affirmative	
8	Debra R Warner	Debra R Warner	Abstain	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit H

Standard Drafting Team Roster for Project 2010-14.1

Project 2010-14.1 BARC - Reserves

Name and Title	Company	Contact Info	Bio
Glenn Stephens - Chair	Santee Cooper	843.761.8000 x-4482 glenn.stephens @santeecooper.com	Mr. Stephens is Manager of System Planning at Santee Cooper. His responsibilities include managing the planning of the Bulk Electric System as well as planning, designing, and operating the communications system. He earned a Bachelor of Science in Electrical Engineering degree from Clemson University in 1983 and Master of Business Administration from University of South Carolina in 1995. He has 31 years of experience in the electric power industry having spent his entire career with Santee Cooper and has worked in many areas including: system operations, system planning, metering operations, communication operations and planning, distribution operations, protection operations, and substations operations. He is a registered Professional Engineer in state of South Carolina and is NERC certified operator at the RC level.

Tom Siegrist – Vice-Chair	Brickfield, Burchette, Ritts and Stone, P.C.	678. 520.6954 tom.siegrist@bbrslaw.com	Mr. Siegrist has 40 years of electric utility experience, including electric system operations and maintenance, system protection and control, engineering design, and system planning. In his current position with Brickfield, Burchette, Ritts and Stone (BBRS), Mr. Siegrist provides electric industry related engineering consulting services to the firm and its clients. Before joining BBRS, Mr. Siegrist was a founding owner of the consulting firm, EnerVision, Inc. where he led the firm's transmission, system operations and NERC compliance practice areas for 15 years. Prior to the formation of EnerVision, Mr. Siegrist served for 20 years in several senior positions with Oglethorpe Power Corporation (OPC) including Vice President positions in Electric System Operations, Electric System Planning, Transmission Engineering, Telecommunications, and Transmission Operations & Maintenance. In Electric System Operations, Tom developed and directed efforts to establish OPC's control center operations, enabling Oglethorpe Power to participate in power markets for the first time. This included the implementation of real-time operations and compliance with NERC/SERC reliability standards. Prior to joining Oglethorpe Power Mr. Siegrist worked at Florida Power & Light Company as a System Protection Test Engineer. Mr. Siegrist holds a Bachelor Degree in Electrical Engineering from The Georgia Institute of Technology, and is a registered Professional Engineer in the State of Georgia.

Gerry Beckerle	Ameren	314.554.6413 GBeckerle@ameren.com	Gerald D. Beckerle, Senior Transmission Operations Supervisor, Ameren Services, St. Louis, MO, has a BSEE from the University of Missouri, Columbia. He has been with Ameren for 33 years, 26 of those years in System Operations, which has been or currently responsible for Transmission, Generation, and daily interchange. Current activities include: NERC OC IOU Representative 2013-2015, serving on OC executive committee NERC Resources Subcommittee Chairman 2014-2016 NERC Balancing Authority Reliability Based Controls Standard Drafting Team member SERC Operating Committee Member Past Activities included: NERC Operating Committee Member RE Representative 2011-2013 SERC Operating Committee Chairman 2011-2013 NERC Frequency Response Standard - Drafting Team Contributor Balancing Authority Controls SAR and SDT member prior to merging into the BARC SDT. Midwest Reserve Sharing Group - representative for Ameren RFC Version Zero Standards Drafting Team member MAIN Operating Reserve Subcommittee member

Howard Illian President	Energy Mark, Inc.	847-913-5491 howard.illian@energymark.com	Howard F. Illian graduated from Carnegie Institute of Technology (Carnegie-Mellon University) in 1970 with a B.S. in Electrical Engineering. From 1970 until 1982 he worked for ComEd in the field of Operations Research, and was Supervisor, Economic Research and Load Forecasting from 1976 until he was reassigned to Bulk Power Operations in 1982 where he was Technical Services Director when he retired in 1998. He is now President of Energy Mark, Inc., a consulting firm specializing in the commercial relationships required by restructuring. He has authored numerous papers, and has testified as an expert witness before the Illinois EPA, the Federal EPA, the Illinois Commerce Commission, the Public Utility Commission of Texas, and the Federal Energy Regulatory Commission. He has developed and applied several new mathematical techniques for use in simulation and decision making. He has served on the NERC Performance Subcommittee, the Interconnected Operations Services Implementation Task Force, the Joint Inadvertent Interchange Task Force, and the NAESB Inadvertent Interchange Payback Task Force. Recent work includes significant contributions to the development of new NERC Control Performance Standards including the Balancing Authority Ace Limit and a suggested mathematical foundation for control based on classical statistics. His current research concentrates on the development of technical definitions for Ancillary or Reliability Services including frequency response and their market implementation.

David Lemmons – Chair Senior Consultant	Xcel Energy, Inc	303.628.2813 david.f.lemmons@xcelenergy.com	David Lemmons began his career in the electric industry with Southwestern Public Service Company (SPS) in Amarillo, Texas in 1989. He spent 8 years in the Rates and Regulation Department where he performed rate of return analyses, designed rates and worked with other regulatory issues. In 1997, David moved to the Energy Trading Department during the merger between SPS and Public Service Company of Colorado (PSCo). In this capacity, with Xcel Energy and its predecessor, New Century Energies, he analyzed the electric system loads and resources for day-ahead and real-time operations and trading, working with generation and fuel procurement to ensure resources were ready and available to serve loads. From 2001 to 2013, in the positions of Manager and Senior Manager of Market Operations, he has represented Xcel Energy at electric reliability, RTO development and system operation meetings throughout the United States as well as providing support for state and Federal regulatory proceedings. In 2013, David moved into the Energy Supply Compliance area where he works with generators to ensure compliance with applicable NERC and Regional standards. He has a Masters of Science in Finance and Economics from West Texas A&M University.

Clyde Loutan Senior Advisor	California ISO	916-608-5917 cloutan@caiso.com	Clyde Loutan is presently a Senior Advisor at the California Independent System Operator Corporation (ISO) focusing on power system operation performance, and is the lead investigator for the ISO's renewable resource integration technical studies. He is a technical subject matter expert on power grid planning, system operations, and renewable energy integration. Mr. Loutan previously worked at the Pacific Gas and Electric Company for 14 years in various capacities such as Real Time System Operations, Transmission Planning and High Voltage Protection. Mr. Loutan is a licensed professional engineer in the State of California. He holds B.S. and M.S. degrees in Electrical Engineering from Howard University in Washington D.C., and is a senior member of the IEEE.
LeRoy Patterson	Puget Sound Energy	425.882.4433 Leroy.Patterson@pse.com	Mr. Patterson is an executive with years of experience and extensive knowledge of electric system operations, SCADA and Energy Management Systems (EMS), regulations, and the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards development and compliance programs. Since September 2012, Mr. Patterson has worked at Puget Sound Energy (PSE) training System Operators. His utility career began as a transmission planner for Pacific Gas & Electric. He has 18+ years working in operations at Montana Power Company and NorthWestern Energy, 3 years as director of operations at the Western Electricity Coordinating Council, and 4+ years at Patterson Consulting, Inc. and Utility Systems Efficiencies, Inc. Mr. Patterson has been active within electric industry organizations such as Northwest Power Pool Operating Committee, Western Systems Coordinating Council (now WECC), and NERC. His activities in these and other regional forums have included leadership positions in many cases such as being the chair of the operating committee of both the NWPP and WSCC.

Mike Potishnak Principal Engineer	Spriteland Energy	413-323-8834 mpot@charter.net	Mike Potishnak is President of Spriteland Energy and is representing NPCC in the development of Balancing Standards as a consultant. Mike has a B.S in E.E. and an M.S. in M.E., with over 40 years of utility experience, working previously for Con Edison, Public Service Colorado, and ISO New England.
Mark Prosperi-Porta	BC Hydro	Mark.Prosperi-Porta@bchydro.com	Mr. Prosperi-Porta joined BC Hydro in 1990 after graduating with a Bachelor of Applied Science in Electrical Engineering. Worked in engineering, design, market operations and system operations over the next 24 years. Currently is a System Control Manager and oversees the Real-time operation of distribution, transmission, generation and bulk electric system in BC.
Tom Pruitt	Duke Energy Carolinas, LLC	704-382-4676 Tom.Pruitt@duke-energy.com	Tom Pruitt is a Principal Engineer with Duke Energy and has over 30 years' experience in almost all facets of operation in a vertically-integrated utility, the last 17 in system operations. He chairs sub-regional operating and reserve sharing group committees and is a member of the NERC Resources Subcommittee. He is his company's subject matter expert (SME) on BAL and COM standards. He has a BSEE from North Carolina State University and is a NERC-certified Reliability Coordinator and licensed Professional Engineer (NC).

Jerry Rust President	Northwest Power Pool	503.445.1074 jerry.rust@nwpp.org	Jerry D. Rust joined the Northwest Power Pool January 1, 2001 as President. For the majority of 2000, Jerry consulted on power issues for several software companies. Prior to that, he worked at PacifiCorp for 23 years, where he served as managing director of PacifiCorp's revenue organization and managing director of the transmission systems group. Jerry joined PacifiCorp in 1977 as an engineer and held positions in power resources, financial analysis, field operations, customer service, sales support and national sales. Mr. Rust was graduated from the University of Wyoming with a degree in electrical engineering. He has furthered his education with numerous courses from various schools (University of Washington, Washington State University, Colorado School of Mines, and others). Jerry is one of the Western Electricity Coordinating Council's North American Electric Reliability Council Operating Committee Representatives.
Steve Swan	MISO	317-249-5075 SSwan@misoenergy.org	Steve Swan is the Senior Manager of Dispatch and Balancing at the Midcontinent Independent System Operator, Inc. where he is the manager of all system wide market dispatch and balancing functions for a fleet of over 100,000 MW of MISO controlled generation.

Tom Washburn Executive Director	Florida Municipal Power Pool	407-434-4228 TWashburn@ouc.com	With over 40 years of experience, Tom Washburn has provided a diverse set of services to Orlando Utilities Commission and the Florida Municipal Power Pool. As Vice President of the Transmission Unit at Orlando Utilities Commission, he was responsible for the planning, regulatory permitting, construction and operation of over 300 miles high voltage transmission lines, over 30 high voltage substations, and the 24-by-7 system operations of the transmission and generation system. As the Chief Information Officer at Orlando Utilities Commission, Washburn was responsible for all of the Information Technology including microcomputer support, computer applications, computer hardware, telecommunication and the fiber optics data communications. In other management roles at Orlando Utilities Commission, he was responsible for financial planning, load forecasting, rate design, wholesale marketing, and generation planning. Tom Washburn helped form the Florida Municipal Power Pool, which started operation in July 1988. As the first Executive Director of the Florida Municipal Power Pool, since May. 2006, Washburn is responsible for the reliable, economic operation of more than 4,500 megawatts of generation serving 20 municipal utilities in Florida, compliance with the North America Reliability Corporation Reliability Standards, and overseeing the clearinghouse price process for the Pool.

Robert Cummings Director, Reliability Initiatives and System Analysis	NERC	404-446-9717 bob.cummings@nerc.net	Mr. Cummings joined NERC in 1996 and has extensive experience in the industry in system planning, operations engineering, and wide area planning. He holds a Bachelor of Science Degree in Power System Engineering from Worcester Polytechnic Institute and is an IEEE Senior Member. His geographically diverse experience includes Central Vermont Public Service Corporation in System Planning (generation and transmission), Public Service Company of New Mexico, and the East Central Reliability Coordination Agreement (ECAR). Mr. Cummings was the “father” of power interchange transaction “tagging” and the Interchange Distribution Calculator, which shows loading contributions on key system transmission interfaces, or “flowgates,” for the Eastern Interconnection. The Reliability Initiatives and System Analysis group acts provides a consulting engineering function within NERC, performing deep-dive forensic engineering analysis of major system disturbances and providing subject matter expertise to standards drafting teams and various other areas of NERC staff. Cummings was intimately involved in the investigation team of the 2003 blackout as a team leader and the more recent September 8, 2011 Arizona-Southern California Outage analysis. In both instances he led multiple teams with responsibilities in the sequence of events development, modeling and studies (powerflow and dynamics analysis), and transmission/generation performance areas. From 2005 through 2009, he directed the NERC Event Analysis and Information Exchange program, directing or working on 12 major disturbance analyses. Mr. Cummings was instrumental in the founding of the NERC System Protection and Controls Task Force, now the System Protection and Control Subcommittee, acting as the staff coordinator from 2004 through 2009.

			Mr. Cummings is the staff coordinator for the NERC System Analysis and Modeling Subcommittee and is the technical advocate in the North American Synchro-Phasor Initiative. He is also the technical director of the NERC System Protection and Control Performance Improvement Initiative, the Modeling Improvements Initiative, and the Frequency Response Improvement Initiative.
Darrel Richardson Standards Developer	NERC	609-613-1848 Darrel.richardson@nerc.net	Darrel Richardson joined the NERC staff as a Standards Developer. In this role he facilitates and provides guidance to drafting teams in the development of technically excellent and timely reliability standards for the reliable operation and planning of the bulk power system. Darrel began his career with NERC in November 2007. Darrel has extensive experience in the utility industry having spent over 37 years with Illinois Power Company. In his tenure at Illinois Power he held several different positions in the Engineering, Planning and Operations groups. Among the position he has held are Transmission Coordinator, Generation Coordinator, Manager Wholesale Marketing, Manager Wholesale Marketing and Trading, Director Generation Control and Manager Compliance.